3.0 FACILITY DESCRIPTION AND LOCATION

SECTION 3.0 FACILITY DESCRIPTION AND LOCATION
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3.0 FACILITY DESCRIPTION AND LOCATION

3.1 INTRODUCTION

The proposed Tesla Power Project (TPP) consists of a natural gas-fired combined cycle power plant and associated linear facilities. The project will have a nominal electrical output of 1,140 MW with commercial operation planned to begin in the 2^{nd} quarter of 2004. The project will be fueled with natural gas that will be delivered to the power plant site via a new 24-inch diameter, 2.8-mile pipeline. The plant switchyard will be connected to the Pacific Gas and Electric Company (PG&E) Tesla Substation with a new 0.8 mile long transmission line. Water for the project will be provided by the Rosedale-Rio Bravo Water Storage District in Kern County, delivered from the California Aqueduct via a new 20-inch, 1.7-mile pipeline adjacent to Midway Road. Wastewater will be processed by a zero liquid discharge (ZLD) system.

3.2 LOCATION OF FACILITIES

TPP site which includes the power generation facility, switchyard and a storm water sedimentation/detention pond will be located on a 60 acre parcel (Assessor's Parcel Number 099B-7825-001-04) in Section 30, Township 25, Range 4E, approximately 0.5 mile north of the PG&E Tesla Substation. The plant site, controlled under a purchase and sale agreement, is bordered by an abandoned railroad right-of-way to the north and Midway Road to the east. Figure 3.2-1 Regional Project Location, illustrates the power plant location and nearby roads. Figure 3.2-2 illustrates the location of the power plant site, water pipeline, natural gas supply pipeline, and the transmission line.

3.3 POWER PLANT SITE DESCRIPTION

TPP's power generation facility, switchyard and a storm water sedimentation/detention pond will occupy approximately 25 fenced acres within the 60-acre parcel, as illustrated in Figure 3.3-1, Site Plan. The project site is presently undeveloped agricultural land used for grazing cattle. Site topography ranges from approximately 360 to 400 feet above mean sea level (amsl). The plant grading elevation is estimated to be about 380 feet amsl.

3.4 POWER GENERATION FACILITY

The following sections describe the power generation facility site arrangement, process flow diagrams and heat and material balances, major equipment and ancillary systems, including buildings and structures that constitute the proposed combined cycle power plant. The combined cycle power plant will be designed, constructed, and operated in accordance with applicable laws, ordinances, regulations, and standards (LORS). In addition, the power plant facilities will be designed and constructed in accordance with the design criteria provided in Appendices A through E.

3.4.1 Power Plant Site Arrangement

The plant and switchyard arrangements are illustrated in Figure 3.4-1, Plot Plan. Elevations are shown in Figures 3.4-2 and 3.4-3 and an oblique view of the proposed power generation facility is shown in Figure 3.4-4.

A short 24-foot wide road will provide access to the power plant site from Midway Road, as illustrated in Figure 3.3-1. A 20-foot wide, paved perimeter road provides access within the power generation facility.

The power generation facility includes the parking area, administration, control and maintenance buildings, turbine generators and emission control equipment, cooling tower, water treatment building, water storage tanks, and water treatment facilities. A 5 acre-feet storm water runoff pond occupies approximately 1.5 acres.

3.4.2 Process Description

This section describes the power generation process and thermodynamic cycle employed by the proposed project.

The power plant consists of four combustion turbine-generators (CTGs) equipped with dry low NO_x combustors, and inlet air foggers; four heat recovery steam generators (HRSGs) equipped with duct burners; two steam turbine-generators (STG); and associated auxiliary systems and equipment. Fuel for the CTGs and duct burners is natural gas. With the duct burners and inlet air foggers in-service and the CTGs at full load, the HRSGs produce sufficient steam to operate the STG at its full rated capacity.

Each CTG generates approximately 162 MW gross at 97°F ambient temperature and inlet air foggers in-service. Heat from the CTGs' exhaust gases is used in the HRSGs to generate steam and to reheat steam. All of the steam exiting the HRSGs is directed to the STG, which generates approximately 185 MW of gross power. The overall gross output of the power plant is 509 MW at this condition. With the HRSGs duct burners in-service, the STG will generate 246 MW while the power plant will produce approximately 570 MW of gross power.

Overall annual availability of the power plant is expected to be in the range of 92 to 96 percent. The power plant's capacity factor will depend on market prices for electricity, ancillary services, and natural gas. The design of the power plant provides for operating flexibility (i.e., ability to start up, shut down, turn down, and provide peaking output) so that operations may be readily adapted to changing conditions in the energy and ancillary services markets.

Process flow diagrams of the power plant are shown in Figures 3.4-5 and 3.4-6. Figure 3.4-5 shows the power block and Figure 3.4-6 shows the balance of plant, which includes the circulating water system and the water storage and treatment systems. Six operating cases are summarized in Table 3.4-1, Heat and Material Balance Case Descriptions. Heat and material balances at six different operating conditions, each at three CTGs loads (100%, 75% and 50%) are presented in Tables 3.4-2 through 3.4-7. The stream numbers on the heat and material balances correspond to numbered diamonds on the process flow diagrams.

Table 3.4-1 Heat and Material Balance Case Descriptions

Case Number	Description	Ambient Temperature, °F	Relative Humidity, %	Duct Fire Status	Fogger Status
1	Maximum	112	15	On	On
2	Hot Summer Day	97	21	On	On
3	Hot Summer Day	97	21	Off	On
4	Yearly Average	62	70	On	On
5	Yearly Average	62	70	Off	On
6	Minimum	17	83	Off	Off

The following provides a brief description of the power plant's thermodynamic cycle:

Air flows through the CTG inlet air filter, foggers, and associated ductwork to the CTG compressor section. The compressed air from the compressor section flows to the CTG combustor section where it is mixed with compressed natural gas and ignited. The hot combustion gases flow through the CTG turbine expander section which drives both the CTG compressor section and electric generator. The combustion gases exit the turbine expander section and enter the inlet duct of HRSG which are equipped with duct burners. The burners, when fired, heat up the exhaust gases which then enter the HRSG steam generation section.

In the HRSG's steam generation section, heat from the combustion gases is transferred to water pumped through the HRSG steam generation components (economizers, evaporators, drums, superheaters, etc.). The water is converted to steam at three pressures: high-pressure (HP), intermediate-pressure (IP) and low pressure (LP), superheated and delivered to the STG. HP steam admitted to the HP section of the STG, expands through the HP section and exits the HP section as "cold" reheat steam. The "cold" reheat steam is combined with superheated IP steam and returned to the reheater section of the HRSG where it is reheated and returned to the STG continuing its expansion and driving the generator. Reheating the intermediate pressure steam improves the overall steam cycle efficiency. Exhaust steam from the STG enters a surface condenser where it is condensed into water and recycled back to the HRSG as boiler feed water. Cooling water from the condenser tubes is circulated to a wet/dry cooling tower where the absorbed heat is rejected to the ambient atmosphere.

3.4.3 Combustion Turbine-Generators, HRSGs, and Steam Turbine-Generator

This section describes the major components and systems of the proposed project: the CTGs, HRSGs, STG, and Heat Rejection (Cooling) System.

3.4.3.1 Combustion Turbine-Generators

Thermal energy is produced in each of the four CTGs through the combustion of natural gas, and is converted into mechanical energy in the CTG turbine that drives the CTG compressor and electric generator. The CTGs are 7FA machines supplied by GE Power Systems.

Each CTG will consist of a heavy duty, single shaft, combustion turbine-generator and associated auxiliary equipment. The CTGs will be equipped with dry low NO_x combustors designed for natural gas and will meet the following functional requirements:

- Air emissions at the gas turbine exhaust will not exceed the levels described in Section 5.2, Air Quality.
- Noise emissions will not exceed the near-field and property line levels described in Section 5.9, Noise.
- Each CTG will be capable of operation at 50% load while meeting required air emission performance.

The CTGs will be equipped with the following accessories required to provide efficient, safe, and reliable operation:

- Inlet air filters and on-line filter cleaning system
- Inlet air foggers
- On-line and off-line compressor wash system
- Metal acoustical enclosures
- Fire detection and protection system
- Lubrication oil system including oil coolers and filters

- Generator coolers
- Starting system, auxiliary power system, and control system

The metal acoustical enclosures will contain the CTGs and accessory equipment.

3.4.3.2 Heat Recovery Steam Generators

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce steam. The HRSGs will be multipressure, natural circulation boilers equipped with transition ducts and duct burners, and 19-foot diameter exhaust stacks, which will be 200 feet tall.

Pressure components of each HRSG include an LP economizer, LP evaporator, LP drum, LP superheater, IP economizer, IP evaporator, IP drum, IP superheater, HP economizer, HP evaporator, HP drum, HP superheater, and reheaters.

Boiler feed water from the deaerating type condenser is delivered by condensate pumps to the LP economizer. The boiler feed water flows through the LP economizer and on to the LP drum. By natural circulation, the saturated boiler feed water from the LP drum flows through downcomers to the inlet headers of the LP evaporator, upward through the LP evaporator where the water is partially converted to steam. The saturated steam and water are separated in the LP drum, and the steam is superheated and is used by the STG. Boiler feed water from the LP drum flows to boiler feed pumps, which deliver water to both the HP and IP sections of the HRSG.

The boiler feed water discharged from the boiler feed pumps at high pressure is delivered to the HP section of the HRSG. This HP feedwater flows through the HP economizer and on to the HP drum where a saturated state is maintained. By natural circulation, saturated water from the HP drum flows through downcomers to the inlet headers of the HP evaporator, upward through the HP evaporator where the water is partially converted to steam, and back to the HP drum. The saturated steam and water are separated in the HP drum, and the steam is delivered to the HP superheater inlet. The superheated steam leaving the HP superheater is delivered to the HP steam admission valve of the STG.

The boiler feed water discharged from the boiler feed pumps at intermediate pressure is delivered to the IP section of the HRSG. This IP feedwater flows through the IP economizer and on to the IP drum where a saturated state is maintained. By natural circulation, saturated water from the IP drum flows through downcomers to the inlet headers of the IP evaporator, upward through the IP evaporator where the water is partially converted to steam, and back to the IP drum. The saturated steam and water are separated in the IP drum, and the steam is delivered to the IP superheater inlet. The superheated steam leaving the IP superheater is delivered to the IP steam admission valve of the STG.

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners reheat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs.

Each HRSG is equipped with a selective catalytic reduction (SCR) system that uses aqueous ammonia in conjunction with a catalyst bed to reduce oxides of nitrogen (NO_x) in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_x to nitrogen and water, resulting in a reduced concentration of NO_x in the exhaust gases exiting the stack.

An oxidation catalyst located within each HRSG reduces the concentration of carbon monoxide in the exhaust gases exiting the stack. The oxidation catalyst also reduces the concentration of volatile organic compound emissions.

3.4.3.3 Steam Turbine-Generator

The STG system includes a reheat steam turbine-generator, governor system, steam admission system, gland steam system, lubrication oil system including oil coolers and filters, and generator coolers.

Steam from the HP superheater, reheater, and IP superheater sections of the HRSG enters the corresponding sections of the STG where it expands and drives the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser where it is condensed to water.

3.4.3.4 Cooling System for Heat Rejection

The plant heat rejection system of the steam cycle consists of two surface condensers, circulating water system and two wet/dry type cooling towers. Each surface condenser is a shell-and-tube heat exchanger with wet, saturated steam condensing on the shell side and circulating water flowing through the tubes. The warm circulating water leaving condensers is directed to the cooling towers where it is cooled in direct contact with air.

The cooling towers proposed for the project will be plume-abated towers. When the towers are operating in a plume-abated mode, the warm water is first circulated through a heat exchanger (dry air) section and then through the evaporative fill (wet) section.

This dry air section will include a non-contact heat exchanger to allow for warm circulating water to preheat air entering the upper portion of the cooling tower, reducing its relative humidity. Use of this system will allow for reduction of plume during visually sensitive circumstances, and will eliminate the possibility for fogging or icing of the adjacent Midway Road. Due to the lower performance of the cooling tower in the plume abatement mode, the system will be used on an as-needed basis.

The circulating water in the wet section is partially evaporated in direct contact with the air and lost to the atmosphere. The cooled circulating water is pumped from the cooling tower basin back to the surface condensers.

3.4.4 Major Electrical Systems and Equipment

This section describes the major electrical systems and equipment for the proposed project. Almost all of the power produced by the plant will be delivered to PG&E. A small amount, however, will be used on-site for the plant auxiliaries such as: cooling tower fans, pumps, control systems, general facility loads including heating, ventilation and air conditioning (HVAC), ZLD system and lighting. Some power will also be converted to direct current (DC) for the plant control and emergency backup systems. An overall one-line diagram of the major electrical systems is presented in Figure 3.4-7.

3.4.4.1 Step-Up Transformers and Plant Switchyard

Power will be generated at 18.0 kV by the four CTGs and two STGs, and then stepped up to 230 kV for delivery to the power plant's interconnection with PG&E. Each of the plant's six generators will be connected by an 18 kV bus to a dedicated 18-230 kV oil-filled, step-up transformer. Each step-up transformer rests on a concrete pad/pit designed to contain the transformer oil in the event of a leak or spill.

The high voltage side of each step-up transformer will be connected to one of two 230 kV collector buses. Each of the two collector buses will include four 230kV breakers and will provide terminal positions for one combined cycle unit (two CTG's and one STG) and one 230 kV circuit to PG&E's Tesla substation. Figure 3.4-7 shows the configuration of the step-up transformers and the plant switchyard. Additional information on the transmission interconnection with the PG&E Substation system is provided in Section 3.6.

3.4.4.2 Electrical System for Plant Auxiliaries

Power for plant auxiliaries will be supplied at 4160 V from the 230 kV plant switchyard. Four 18 kV-4160 V oil-filled, step-down, auxiliary transformers are connected to the four CTGs between the generator breakers and the CTG main step-up transformers. The low voltage side of the auxiliary transformers is connected to 4160 V switchgear. This configuration allows the power for plant auxiliaries to be supplied from the plant switchyard regardless of whether the CTGs and STGs are on-line or off-line. The auxiliary transformers rest on concrete pads designed to contain the transformer oil in the event of a leak or spill.

The 4160 V switchgear distributes power to the plant's 4160 V motors, to the CTG starting systems, and to 4160-480 V dry-type transformers. The low voltage side of the 4160-480 V dry-type transformers is connected to 480 V switchgear. The 480 V switchgear distributes power to the plant's large 480 V loads and to 480 V motor control centers (MCCs). The MCCs distribute power to the plant's intermediate 480 V loads and to power panels serving small 480 V loads.

The MCCs also distribute power to 480-277 V dry-type isolation transformers serving 277 V single-phase loads and to 480-208/120 dry-type transformers serving 208 V and 120 V loads. An overall one-line diagram of the auxiliary electrical systems is presented in Figure 3.4-8.

3.4.4.3 DC Power Supply System

The plant's DC power supply system will consist of a bank of 125 V DC batteries, a 125 V DC battery charger, metering, ground detectors, and distribution panels. In addition, a similar DC power supply system will be provided as part of each CTG's auxiliary power system.

Under normal operating conditions, the battery charger supplies DC power to the DC loads. The battery charger receives 480 V, three-phase AC power from the electrical system serving plant auxiliaries. The battery charger continuously charges the battery bank while supplying DC power to the DC loads. Under abnormal or emergency conditions when AC power is not available, the battery bank supplies DC power to the DC loads. The battery bank will be sized to power the DC loads for a sufficient amount of time to provide for safe and damage-free shut down of the power plant. Recharging of the battery bank occurs whenever AC power becomes available.

The DC power supply system provides power for critical control circuits, power for control of the 4160 V and 480 V switchgear, and power for DC emergency backup systems. Emergency backup systems include DC lighting and DC lube oil and seal oil pumps for the CTGs and STG.

3.4.4.4 Essential Service AC System

An essential service AC system (120 V, single-phase) provides power to essential instrumentation, critical equipment loads, safety systems, and equipment protection systems that require uninterruptible AC power. The essential service AC system and the DC power supply system will be designed to ensure that critical safety and equipment protection control circuits are always energized and able to function in the event of unit trip or loss of AC power.

The essential service AC system will consist of an inverter, a solid-state transfer switch, a manual bypass switch, an alternate AC source transformer and voltage regulator, and AC panelboards.

The DC power supply system is the normal source of power to the essential service AC system. Power flows from the DC power supply system through the inverter to the AC panelboards. The solid-state transfer switch continuously monitors both the inverter output and the alternate AC source. Upon loss of the inverter output and without interruption of power, the transfer switch automatically transfers essential service AC loads from the inverter output to the alternate AC source. The manual bypass switch enables isolation of the inverter and transfer switch for testing and maintenance without interruption of power to the essential service AC loads.

3.4.4.5 Emergency Diesel Generator

An emergency diesel generator provides power to the essential service AC system in the event of grid failure or loss of outside power to the plant. The generator can be started via a remote control or local panel and has a day tank.

3.4.5 Fuel Supply and Use

This section describes the quantity of fuel required by the proposed project and the source and quality of the fuel.

Estimated fuel consumption at base load and 62°F ambient without duct firing is 151,740 million Btu per day, lower heating value. The fuel consumption at the same conditions with duct firing is 174,360 million Btu per day. For other fuel consumption data, see Tables 3.4-3 through 3.4-8.

The project will be fueled with natural gas supplied from a PG&E backbone pipeline south of the intersection of I-205 and Patterson Pass Road, in San Joaquin County. Natural gas will be conveyed to the power plant site via a new 24-inch 2.8-mile supply pipeline. The route of a new supply pipeline and its tie in to the power plant are illustrated in Figures 3.2-2 and 3.4-1, respectively. Table 3.4-8 presents a typical fuel gas analysis.

Table 3.4-8 Typical Pipeline Quality Natural Gas Analysis

Constituent	Percent by Volume
Methane	93.86
Ethane	3.00
Propane	0.10
n-Butane	0.01
i-Butane	0.01
n-Pentane	0.00
i-Pentane	0.01
Hexane+	0.01
Oxygen	0.00
Carbon dioxide	0.66
Nitrogen	2.35
TOTAL	**100.00**
Sulfur (grains per 100 scf)	<0.33
Specific Gravity (air = 1.00)	0.59
Higher Heating Value (Btu per scf)	1010

Btu = British thermal units.
scf = standard cubic feet.
Source: PG&E

The natural gas will be delivered to the plant metering station at a pressure greater than 550 pounds per square inch, gauge (psig). A revenue-quality flow meter will be provided at the downstream end of the new supply pipeline. The pipeline will be also provided with isolation valves and vent valves to allow the pipeline and associated equipment to be depressurized for maintenance or repair.

The natural gas will be letdown to a minimum pressure of 550 psig, filtered and pressure-regulated prior to entering the CTG and duct burner systems. Safety pressure relief valves will be provided downstream of the pressure regulation station. Each CTG fuel gas system will include a fuel gas preheater which uses hot water from the HRSG.

3.4.6 Water Supply and Consumptive Requirements

This section provides estimated consumptive use of water and describes its source, quality and proposed water treatment systems. The power plant's various water uses include makeup for the circulating water system, makeup for the HRSGs, water for the CTG inlet foggers, makeup for the service water system, potable water, and fire protection water. A water balance diagram is presented in Figure 3.4-9. The plant water balances are shown in Table 3.4-10.

3.4.6.1 Water Consumptive Requirements

Daily, maximum and annual consumption requirements are summarized in Table 3.4-9. Daily requirements are based on daily, continuous plant consumption at average annual operating conditions of 62°F and 70% relative humidity. CTG inlet air foggers are in-service and there is no duct firing. Maximum daily requirements are based on daily, continuous plant consumption at summer extreme conditions of 112°F and 15% relative humidity. CTG inlet air foggers are in-service and there is duct firing. The annual water consumption requirements are derived from plant consumption on a month by month basis. The impact of plant operation with CTG inlet air foggers, duct firing, and cooling tower plume abatement is also considered.

Monthly average and maximum consumption requirements based on the plant various operating scenarios are summarized quarterly in Tables 3.4-11 through 14.

Table 3.4-9 Daily, Maximum and Annual Water Consumption Requirements

Water Service/Use	Daily Consumption Requirements (1) (US gpm)	Maximum Daily Consumption Requirements (2) (US gpm)	Annual Average Consumption Requirements (3) (acre-feet)	Annual Maximum Consumption Requirements (4) (acre-feet)
Demineralized Water to Steam Cycle Makeup	83	123	130	150
Demineralized Water to CTG Foggers	32	225	50	58
Filtered Water to Service Water Users	5	5	8	9
Filtered Water to Potable Water Users	5	5	8	9
Filtered Water to Cooling Tower Makeup	3,106	5,753	4,855	5,608
Filtered Water to Miscellaneous Users	10	0	16	18
Total Plant Water Usage Requirements	3,241	6,111	5,066	5,852

Notes:

1. Daily water consumption requirements are from the Water Balances Table 3.4-10, Case 5; Streams 1, 6, 8, 9, 22 and 23.
2. Maximum daily water consumption requirements are from the Water Balances Table 3.4-10, Case 1; Streams 1, 6, 8, 9, 22 and 23.
3. Annual average water consumption requirements are derived from the Monthly Water Usage Tables 3.4-11 through 3.4-14.
4. Annual maximum water consumption requirements are derived from the Monthly Water Usage Tables 3.4-11 through 3.4-14.

3.4.6.2 Water Source and Quality

Water will be supplied under agreement with the Rosedale-Rio Bravo Water Storage District. Water will be delivered by the Alameda County Flood Control and Water Conservation District Zone 7 using exchanged non SWP water from the California Aqueduct (see also Section 5.4 Water Resources). Water quality analysis for water from the California Aqueduct is presented in Table 3.4-15. A pump station will be required adjacent to the California Aqueduct. The pump station will occupy approximately 0.5 acres. A 1.7-mile pipeline will connect the pumping station with the power plant site. The water will be pumped into a header to supply makeup water to the circulating (cooling) water system and additional non-cooling water for plant process needs. Non-cooling water requirements will include makeup to the heat recovery steam generator (HRSG) water for the combustion turbine inlet foggers, general service water, stored firewater and potable water.

At the power plant site, a raw water/firewater storage tank with a capacity of 8,365,000 gallons will hold 8,065,000 gallons of water for plant operation. This quantity is sufficient to cover a 24-hour interruption of water supplied to the power plant at summer peak conditions. The balance of 300,000 gallons of the raw water will be dedicated to the plant's fire protection water system.

3.4.6.3 Water Treatment

The Water Balance Diagram, Figure 3.4-9, shows the power plant's water treatment processes and the distribution of treated water. All water used at the plant is filtered and treated, with the exception of fire protection water that is only filtered. Water treatment varies according to the quality required for each of the plant's various water uses: circulating water, HRSG makeup, CTG foggers, service water, and potable water. The following sections describe the plant's water uses and treatment.

3.4.6.4 Circulating Water

Makeup water for the circulating water system is supplied by the raw water / firewater storage tank. The circulating water chemical feed system will supply water conditioning chemicals to the circulating water system to maintain pH, minimize corrosion and to control the formation of mineral scale and biofouling.

An inhibitor solution and/or dispersant polymer may be fed into the circulating water system in an amount proportional to the circulating water blowdown flow. The inhibitor solution feed equipment includes chemical containers and two full-capacity metering pumps.

To inhibit biofouling, sodium hypochlorite is shock-fed, or continuously fed, into the circulating water system as a biocide. The sodium hypochlorite feed equipment includes chemical storage tank and two full-capacity metering pumps.

A sulfuric acid feed system is provided to maintain pH of the circulating water. The sulfuric acid feed equipment includes acid storage tank and two full capacity metering pumps.

3.4.6.5 HRSG Makeup and Fogger Supply

Water for the HRSGs and foggers must meet stringent specifications for suspended and dissolved solids. To meet these specifications, water supplied from the water storage tank or ZLD is demineralized. Demineralization is accomplished using reverse osmosis process and/or ion exchange equipment (mixed bed unit). Storage of demineralized product water is provided in a 440,000 gallon demineralized water storage tank, which provides sufficient capacity for 24 hours of peak load operation coinciding with an outage of the water treatment system.

Additional conditioning of the condensate and feedwater circulating in the steam cycle is provided by means of a chemical feed system. An oxygen scavenger (Carbohydrazide) for dissolved oxygen control and 19.0 wt% aqueous ammonia for corrosion control are fed into the condensate. To minimize scale formation, a solution of alkaline phosphate is fed into the feedwater of both the HP and IP drums of the HRSG. The chemical feed system includes oxygen scavenger chemical containers, aqueous 19.0 wt% ammonia chemical containers, phosphate solution chemical containers for the HP drum, and phosphate solution chemical containers for the IP drum. Each of the chemical containers is provided with two full-capacity metering pumps, except the phosphate chemical feed system which has two full-capacity metering pumps plus a common spare.

A steam cycle sampling and analysis system monitors the water quality at various points in the plant's steam cycle. The water quality data is used to guide adjustments in water treatment processes and to determine the need for other corrective operational or maintenance measures. Steam and water samples are routed to a sample panel where steam samples are condensed and the pressure and temperature of all samples are reduced as necessary. The samples are then directed to automatic analyzers for continuous monitoring of conductivity and pH. All monitored values are indicated at the sample panel and critical values are transmitted to the plant control room. Grab samples are periodically obtained at the sample panel for chemical analyses that provide information on a range of water quality parameters.

3.4.6.6 Service Water

Utility stations in various locations of the facility provide service water to washdown tools, equipment and areas adjacent to the utility station.

Service water is also usually combined with propylene glycol and a corrosion inhibitor for a one-time fill of the closed-loop cooling water system.

3.4.6.7 Potable Water

The raw water supplied by the California Aqueduct will be filtered and hypo-chlorinated for potable water use. The potable water will be used for toilets, showers, emergency eyewash and shower stations. Bottled water will be used for drinking.

3.4.7 Waste Management

This section describes the waste management processes leading to proper collection, treatment, and disposal of wastes. Wastes include wastewater, solid non-hazardous waste, and hazardous waste. Additional information on waste management can be found in Section 5.13, waste management.

3.4.7.1 Solid Non-Hazardous Waste

The operation and maintenance of the plant generates non-hazardous solid wastes typical of power generation facilities. These wastes include scrap metal and plastic, insulation material, paper, glass, empty containers, sludge from the ZLD system, and other miscellaneous solid wastes. These materials are collected for recycle or transfer to landfill in accordance with applicable regulatory requirements.

3.4.7.2 Hazardous Waste

The methods used to properly collect and dispose or recycle hazardous waste generated by the plant depend on the nature of the waste. Hazardous wastes generated by the plant include spent SCR catalyst, used oil filters, used oil, and chemical cleaning wastes. Workers will be trained to handle waste generated at the site.

Spent SCR catalyst will be recycled by the catalyst supplier or disposed of in a Class I landfill. Used oil filters will be recycled or disposed of in a Class I landfill. Used oil will be recovered and recycled by a waste oil recycling contractor.

Chemical cleaning wastes consist of acid and alkaline cleaning solutions used for pre-operational chemical cleaning of the HRSG pressure parts and steam cycle piping systems, acid cleaning solutions used for periodic chemical cleaning of the HRSGs, and wash water used in periodic cleaning of the HRSG fire side and CTG. These wastes, which typically have high concentrations of metals, will be accumulated temporarily on-site in portable tanks and disposed of off-site by chemical cleaning contractors. These and all other hazardous solid and liquid wastes will be disposed of in accordance with applicable laws, ordinances, regulations, and standards.

3.4.7.3 Wastewater

The Water Balance Diagram, Figure 3.4-9, shows the power plant's wastewater streams and the disposition of wastewater. There are two separate wastewater collection systems. The first is the plant wastewater system, which collects wastewater from all plant equipment, including the cooling tower and HRSGs, water treatment system, and general plant drains. The second is the sanitary system, which collects sanitary wastewater from sinks, toilets, and other sanitary facilities and discharges it to an on-site septic system. The sanitary system is based on gravity flow and may include lift stations if required.

The plant wastewater system collects all wastewater generated in the operation of the plant and delivers it to a ZLD system (see Section 3.4.7.4). The ZLD system consists of a vapor compression evaporator that concentrates the plant wastewater and recovers low TDS

(<10 ppm) distillate for reuse as makeup water to the mixed bed demineralizer. Any remaining distillate is reused as makeup water to the cooling tower. Final design may include a preconcentration step that utilizes membrane technologies. The concentrated brine blowdown is directed to a crystallizer where the brine is evaporated to near dryness (<10% moisture), producing a salt that will be trucked to an offsite facility for disposal. The composition of the salt produced is as shown below in Table 3.4-16.

Table 3.4-16 Estimated Composition of Crystallizer Solids

Constituents	Wt%
Calcium	6.1
Magnesium	0.8
Sodium	14.2
Potassium	1.6
Barium	0.02
Bicarbonate	40.9
Chloride	7.24
Sulfate	16.4
Nitrate	1.4
Nitrite	0.2
Fluoride	0.04
Aluminum	0.0088
Antimony	0.002
Arsenic	0.0006
Barium	0.02
Beryllium	0.0003
Bromide	0.064
Cadmium	0.001
Chromium	0.002
Copper	0.002
Iron	0.015
Manganese	0.002
Mercury	0.0002
Nickel	0.0006
Selenium	0.0003
Silver	0.001
Zinc	0.003
Silica	0.79
Bound Water	10.00
Total	**100.0**

3.4.7.3.1 Circulating Water System Blowdown

The cooling tower basin is the collection point for much of the wastewater generated in the plant. Plant wastewater therefore becomes part of the large volume of circulating water flowing through the cooling tower basin. The circulating water is cycled to approximately 20 cycles of concentration for most constituents, depending on the actual water quality characteristics encountered during plant operations. The concentration of dissolved solids in the circulating water will be maintained below the allowable limits, primarily for silica and hardness, through the cooling tower blowdown. The loss of circulating water due to the blowdown is offset with the make-up water and recycled water from the ZLD system.

3.4.7.3.2 HRSG Blowdown

Water circulating in the plant's steam system accumulates dissolved solids that must be maintained below allowable limits to prevent their deposition on heat transfer surfaces of the HRSGs and the steam turbine components. The concentration of dissolved solids is maintained below the allowable limits by blowing down a portion of the water from the HRSG steam drums. The loss of water due to blowdown is offset with water from the demineralization process. The HRSG blowdown is routed to the cooling tower basin.

3.4.7.3.3 Water Treatment System Wastewater

When in use, the reverse osmosis equipment will continuously produce a concentrated reject water stream that contains all of the dissolved solids removed from the product water stream. This reject water stream will be routed to the cooling tower basin.

The final ion-exchange equipment that is used to demineralize HRSG makeup and produce fogger supply water generates both acidic and alkaline wastewater streams. This equipment's periodic regeneration cycle will be performed off-site and therefore is not a part of the on-site waste production.

3.4.7.3.4 Chemical Feed Area

All chemical feed areas will be provided with containment curbs to capture spillage, tank overflows, maintenance operations, and area washdowns. At the lowest point in the containment area, a drain pit will be provided to house a potable pump. If the water is contaminated, it is removed by truck for offsite treatment and disposal.

3.4.7.3.5 General Plant Drainage

General plant drainage consists of wastewater produced by sample drains, equipment drains, equipment leakage, and area washdowns. This wastewater is collected in the general plant drainage system, which consists of floor drains, sumps, and piping. General plant drainage that potentially contains oil or grease is routed through an oil/water separator. Wastewater collected in the general plant drainage system is routed to the cooling water system.

3.4.7.4 Zero Liquid Discharge System

The water balance diagram, Figure 3.4-9, shows all the plant wastewater streams feeding the ZLD system. The plant wastewater that includes cooling tower blowdown, clean water from the oily water separator, media filter backwash water and miscellaneous plant non oily wastewater. These are the feed water streams to the ZLD system (Mechanical Vapor Compression Evaporator and Crystallizer).

3.4.7.4.1 ZLD Process Description

The plant waste streams are continuously fed to an agitated feed tank where the pH is adjusted to 5-6 using sulfuric acid to convert potentially scaling HCO_3 to CO_2.

The feed is then pumped from the feed tank through a plate heat exchanger and heated to near boiling by recovering the distillate's sensible heat. The hot feed then passes through a deaerator where carbon dioxide (CO_2) and other non-condensables are stripped before entering the evaporator (brine concentrator).

The brine slurry from the sump is continuously recirculated to the top of the vertical heat-transfer tubes where it flows through distributor inserted into the top of each tube and falls as a thin film inside. A portion of the thin film is vaporized by a mechanical vapor compressor.

In a vapor compression thermodynamic cycle the vapor is compressed and introduced into the shell side of the vertical tube bundle. The temperature difference between the vapor and the brine film causes the vapor to release its heat of condensation to the falling brine and to condense on the outside of the tubes as distilled water. This distillate is collected at the bottom of the condenser and flows to the distillate tank through a pipe handling both liquid and steam. A small vent stream from the distillate tank maintains the evaporator vessel at a slightly positive pressure. The hot distillate is pumped through the heat exchanger where it gives up its sensible heat to the incoming feed. From this point, the distillate is available as feed to the Mixed Bed demineralizer system.

To avoid scale buildup in the evaporator, a slurry of calcium sulfate (seed) is continuously circulated over the wetted surfaces in the evaporator. As the water is evaporated from the brine film inside the tubes, the remaining brine film becomes super-saturated and calcium sulfate and silica precipitate promoting crystal growth in the slurry. The silica crystals attach themselves to the calcium sulfate crystals.

A portion of the concentrated brine is continuously withdrawn from the sump for discharge to a feed tank and is then transferred to a crystallizer to reduce the waste to dry salt cake. The dry solids are trucked to an approved outside solid waste disposal facility.

In some applications this product as a wet solid has commercial value, but at this time it is not known if this will be the case for TPP. The AFC assumes non-hazardous waste disposal of these solids. The aggregate of these waste solids will be identical to the components in the plant influent water with some additional sulfate ions added due to the addition of acid. Estimates of this waste based on historical water analyses shows it to be well under RCRA TTLC limits and under California STLC limits. The estimated composition of the crystallizer solids is as shown in Table 3.4.16.

3.4.8 Hazardous Material Management

There will be a variety of hazardous materials used and stored during construction and operation of the proposed project. All hazardous materials will be stored in appropriate storage facilities. Bulk materials will be stored in tanks, and other materials will be stored in delivery containers. All hazardous material storage and use areas will be designed to contain leaks and spills. Containment structures will be provided with sufficient volume to contain the spill of a full tank without overflow. For multiple tanks located within a single containment structure, the largest single tank will be used to size the containment volume.

The aqueous ammonia storage tank for the SCR system will be provided with a containment structure and other safety features.

Safety showers and eyewashes will be provided in the chemical feed areas. Service water hose connections will be provided near the chemical feed areas to facilitate flushing of leaks and spills of non-water reactive materials. Appropriate safety gear will be provided for plant personnel for use during the handling, use, and cleanup of hazardous materials. Plant personnel will be properly trained in the handling, use, and cleanup of hazardous materials used at the plant and in procedures to be followed in the event of a leak or spill. Adequate supplies of appropriate cleanup materials will be stored on-site.

All electric equipment will be specified to be free of polychlorinated biphenyls (PCBs). A list of the hazardous materials anticipated to be used at the plant is provided in Table 3.4-17. Each material is identified by type, intended use, and estimated quantity to be stored on-site. Additional information on hazardous material management can be found in Section 5.12.

Table 3.4-18 provides an estimate of the number of trips and anticipated routes for the transportation of hazardous materials and hazardous waste to and from the site (all by trucks).

3.4.9 Air Emissions Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs and HRSG's duct burners are controlled by the state-of-the-art systems. Emissions that are controlled include oxides of nitrogen (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), fine particulate matter (PM_{10}), and sulfur dioxide (SO_2). A continuous Emissions Monitoring (CEM) system will be installed to monitor the stack emissions. All emissions values stated in the following subsections are based on parts per million by volume, dry basis (ppmvd) corrected to 15% oxygen (O_2). A complete analysis of air quality issues, including emissions and ambient impacts, is provided in Section 5.2.

3.4.9.1 NO_x Emissions Control

Dry low NO_x (DLN) combustors in the CTGs followed by selective catalytic reduction (SCR) in the HRSGs will control stack emissions of NO_x to a maximum 2.0 ppmvd (3-hour average excluding startups). The DLN combustors control NO_x emissions to approximately 9 ppmvd at the CTG exhausts by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing the flame temperature and the concentration of oxygen at the flame front.

The SCR process uses aqueous ammonia (NH_3) as a reagent. Stack emissions of ammonia, referred to as "ammonia slip", will not exceed 5 ppmvd. The SCR system includes a catalyst chamber located within each HRSG, catalyst bed, ammonia storage system, and ammonia injection system. The catalyst chamber contains the catalyst bed and is located in a temperature zone of the HRSG where the catalyst is most effective over the range of loads at which the plant will operate. The ammonia injection grid is located upstream of the catalyst chamber. It is expected that the 50,000-gallon aqueous ammonia storage tank will have a 20-day storage capacity at plant's base load operation and ambient temperature of 60°F.

3.4.9.2 CO and VOC Emissions Control

An oxidation catalyst will be provided in the HRSG to limit carbon monoxide (CO) emissions to 6 ppmvd and to ensure that emissions of volatile organic compounds (VOC) are controlled to less than 2 ppmvd at 15 percent O_2. These emission levels correspond to current California and Bay Area Air Quality Management District (BAAQMD) BACT. This catalytic system will promote the oxidation of CO to carbon dioxide and VOC to carbon dioxide and water vapor without the need for additional reagents such as ammonia.

3.4.9.3 PM_{10} and SO_2 Emissions Control

PM_{10} emissions consist primarily of hydrocarbon particles formed during combustion. PM_{10} emissions are controlled by inlet air filtration and by the use of natural gas fuel, which contains essentially zero particulate matter.

SO_2 emissions are controlled by the use of natural gas fuel, which contains only trace quantities of sulfur.

3.4.9.4 Emissions Monitoring

The continuous emissions monitoring system (CEMS) samples, analyzes, and records NO_x, CO, and O_2 concentrations in the stack exhaust. The CEMS generates a log of emissions data for compliance documentation and activates an alarm in the plant control room when stack emissions exceed specified limits.

3.4.10 Fire Protection

Fire protection systems are provided to limit personnel injury, property loss, and plant downtime resulting from a fire. The systems include a fire protection water system, carbon dioxide fire suppression systems for the CTGs, and portable fire extinguishers. The fire protection water will be supplied from a dedicated 300,000-gallon portion of the 8,365,000-gallon raw water /

firewater storage tank located on the power block site. Two 100% fire pumps with a capacity of 2,500 gallons per minute each deliver water to the fire protection water piping network. One of the fire pumps is driven by an electric motor, and the second pump is driven by a diesel engine. A third pump, a small capacity jockey pump driven by an electric motor, maintains pressure in the piping network. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump starts automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump starts automatically. The piping network is configured in a loop so that a piping failure can be isolated with shutoff valves without interrupting the supply of water to a majority of the loop. Fire suppression equipment supplied by the piping network includes fire hydrants and sprinkler systems. Fire hydrants are located at intervals throughout the power plant site. Sprinkler systems are provided in the administration building, control building, and warehouse.

The carbon dioxide (CO_2) fire suppression system provided for each CTG will include a CO_2 storage tank, CO_2 piping and nozzles, fire detection sensors, and a control system. The control system will automatically shut down the CTG, turn off ventilation, close ventilation openings, release CO_2 upon detection, and confirm the existence of a fire. The CO_2 fire suppression systems will cover the turbine enclosure and accessory equipment enclosure of each CTG.

Portable fire extinguishers of appropriate sizes and types will be located throughout the power plant site.

3.4.11 Plant Auxiliary Systems

The following plant auxiliary systems support, protect, and control the power plant.

3.4.11.1 Lighting System

The lighting system provides operations and maintenance personnel with illumination in both normal and emergency conditions. The system consists primarily of AC lighting, and includes DC lighting for activities or emergency egress required during an outage of the plant's AC electrical system. The lighting system also provides AC convenience outlets for portable lamps and tools.

3.4.11.2 Grounding System

The power plant's electrical systems and equipment are susceptible to ground faults, switching surges, and lightning that can impose hazardous voltage and current on plant equipment and structures. To protect against personnel injury and equipment damage, the grounding system provides an adequate path to ground for dissipation of hazardous voltage and current.

The grounding system is provided with adequate capacity to dissipate hazardous voltage and current under the most severe conditions. Bare conductor is installed below grade in a grid pattern, and each junction of the grid is bonded together by welding or mechanical clamps. The grid spacing is designed to maintain safe voltage gradients. Ground resistivity readings are used to determine the necessary grid spacing and numbers of ground rods. Steel structures and non-energized parts of plant electrical equipment are connected to the grounding grid.

3.4.11.3 Distributed Control System

The Distributed Control System (DCS) provides control, monitoring, alarm, and data storage functions for power plant systems.

The following functions will be provided:

- Control of the CTGs, STG, HRSGs, and balance-of-plant systems in a coordinated manner.
- Monitoring of operating parameters from plant systems and equipment, and visual display of the associated operating data to control operators and technicians.
- Detection of abnormal operating parameters and parameter trends, and provision of visual and audible alarms to apprise control operators of such conditions.
- Storage and retrieval of historical operating data.

The DCS is a microprocessor-based system. Redundant capability is provided for critical DCS components such that no single component failure will cause a plant outage. The DCS consists of the following major components:

- CRT-based control operator interface (redundant).
- CRT-based control technician workstation.
- Multi-function processors (redundant).
- Input/output processors (redundant for critical control parameters).
- Field sensors and distributed processors (redundant for critical control parameters).
- Historical data archive.
- Printers, data highways, data links, control cabling, and cable trays.

The DCS is linked to the control systems furnished by the CTG and STG suppliers. These data links provide CTG and STG control, monitoring, alarm, and data storage functions via the CRT-based control operator interface and control technician work station of the DCS.

3.4.11.4 Cathodic Protection System

The cathodic protection system will be used as required to protect against electrochemical corrosion of underground metal piping and structures.

3.4.11.5 Freeze Protection Systems

Due to the infrequency and short duration of below-freezing ambient temperatures at the project site, freeze protection systems will be provided only in applicable areas.

3.4.11.6 Plant / Instrument Air System

The plant and instrument air system consists of all piping, valves, and equipment associated with compressing and distributing air to all essential control and instrumentation elements, and to the non-essential plant users.

The compressor system consists of air compressor skid, which includes oil-free rotary screw compressors with air-cooled intercoolers and aftercoolers, dual coalescing type prefilters, dual tower heatless type regenerative desiccant dryers, dual afterfilters, and an air receiver.

The plant air system supplies compressed air to hose connections located at intervals throughout the power plant. Compressors deliver compressed air at a regulated pressure to the service air piping network.

The instrument air system provides dry, filtered air to pneumatic operators and devices throughout the power plant. Air from the air compressor skid is dried, filtered, and pressure regulated prior to delivery to the instrument air piping network.

3.5 POWER PLANT CIVIL/STRUCTURAL FEATURES

The following sections describe the civil/structural features of the power plant, as illustrated in the site plan presented in Figure 3.3-1. Figures 3.5-1, 3.5-2 and 3.5-3 illustrates the site's existing topography, grading and drainage plan and proposed storm water management and erosion control plan. Temporary construction laydown and craft parking area, shown in Figure 3.5-3, will located on the adjacent 49-acre parcel (Accessor's Parcel Number 99B-7885-1-2).

3.5.1 CTGs, HRSGs, STG and BOP Equipment

The CTGs, STGs, steam condensers, and HRSGs will be supported at grade elevation on reinforced concrete mat foundations. The six step-up transformers and two auxiliary transformers are also supported at grade elevation on reinforced concrete mat foundations. Balance-of-plant mechanical and electrical equipment is supported at grade elevation on individual reinforced concrete pads.

3.5.2 Stacks

Each HRSG will be provided with a self-supporting steel stack. The stacks will be 19 feet in diameter and 200 feet tall. Each stack will include a damper, a silencer, sampling ports, ladders, side step platforms, and electrical grounding.

3.5.3 Buildings

Buildings include the control/administration and maintenance building, electrical relay building, and balance-of-plant mechanical and electrical equipment buildings or enclosures. All buildings are single story and pre-engineered. Building columns will be supported on reinforced concrete mat foundations or individual spread footings. Ground floors will consist of reinforced concrete slabs. Twenty-four parking spaces will be provided on-site to accommodate all employees and visitor vehicles.

3.5.4 Water Storage Tanks

Water storage tanks include a raw water / fire water storage tank with a capacity of 8,365,000 gallons and a demineralized water storage tank with a capacity of 440,000 gallons. Each water storage tank will be a vertical, cylindrical, field-erected steel tank supported on a suitable foundation consisting of either a reinforced concrete mat or a reinforced concrete ring wall with an interior bearing layer of compacted sand supporting the tank bottom as required by the final geotechnical report.

3.5.5 Roads and Fencing

Access to the power plant site will be from Midway Road via a 24-foot wide road as illustrated in Figure 3.3-1. The access road, 20-foot wide plant perimeter road, parking areas, and miscellaneous access drives will be asphalt paved.

Chain link security fencing will be installed around the site boundary and will be also used to enclose the power block, switchyard and other areas requiring controlled access. Controlled access gates will be located at the entrances to the secured areas.

3.5.6 Sanitary Wastewater System

The sanitary wastewater system collects sanitary wastewater from sinks, toilets, and other sanitary facilities and discharges it to a septic tank served by a leaching field.

3.5.7 Site Drainage

The site drainage plan for the proposed facility is shown in Figure 3.5-1. Storm water runoff will be collected by a surface drainage system and directed to a sedimentation/detention basin. The flow of storm water will generally follow the existing drainage pattern toward the southeast corner of the site.

Storm water collected in the curbed areas of the plant facility will be collected in the plant drainage system before being conveyed to the ZLD system.

3.5.8 Earthwork

The existing site topography will be cut and filled to create a plant grade with an approximate elevation of 380 feet above mean sea level. Cut and fill quantities are estimated at 115,000 cubic yards. The project site is not within the 100-year flood zone.

Earthwork on the power plant site will consist of removal and disposal of vegetation and debris, excavation and compaction of earth to create the plant grade, and excavation for foundations and underground systems. Materials suitable for compaction will be stored in stockpiles at designated locations using proper erosion prevention methods. Materials unsuitable for compaction, such as top-soil and large rocks, will be disposed of at an acceptable location. Any contaminated materials encountered during excavation will be disposed of in accordance with applicable laws, ordinances, regulations, and standards.

3.6 TRANSMISSION FACILITIES

This section describes the transmission facilities proposed to interconnect the power plant with the PG&E transmission system. It also describes measures required to mitigate potential overdutied equipment at PG&E's Tesla substation due to an increase in short circuit current level associated with the interconnection of the power plant.

3.6.1 Interconnection to Tesla Substation

Figure 3.6-1 shows the transmission lines in the general vicinity of the TPP and Tesla substation. It is proposed to interconnect the power generation facility with the existing transmission grid via a short 230 kV transmission line with 2 single circuits from the plant switchyard to PG&E's Tesla substation as shown in Figure 3.6-2, Preliminary Transmission Line Routing Plan. Figure 3.6-3 is a conceptual one-line diagram showing the interconnection with the Tesla substation. Figure 3.4-9 is a more detailed one-line diagram of the plant switchyard. The Site Plan, Figure 3.3-1, shows the location of the switchyard in relationship to the plant and existing PG&E transmission lines.

Pursuant to Midway Power LLC's application for interconnection of the plant, PG&E has conducted a System Impact/Facilities Study. A preliminary copy of this report is included in Appendix I. In order to accommodate the termination of the new ties to the TPP PG&E's preference is to re-locate the terminations of two existing transmission lines. Namely, the Tesla-Ravenswood 230 kV line will be re-located to Bus C, which is part of an independent PG&E project underway to expand the Tesla substation; and the Tesla-Newark 230 kV line will be re-terminated from CB232 to CB242 at Bus E. The report also concludes that the primary downstream impact introduced by the project is an increase of the short circuit level at the Tesla substation such that the short circuit rating of existing 230 kV circuit breakers would be exceeded without additional mitigational measures. In addition to the higher short circuit level at the Tesla substation 230 kV buses, the preliminary results from the power flow analysis indicate that overloads may occur on a few transmission lines due to the operation of the TPP. The short circuit duty and line overload problems are discussed later in this section, along with proposed mitigation measures. There will be no significant environmental impacts associated with the mitigation measures.

3.6.2 Interconnection Design Considerations

3.6.2.1 Structures

Several types of structures are being considered for the project transmission lines as shown in Figure 3.6-4. Double-circuit structures are considered the primary structures for the tie from the plant switchyard to Tesla substation. These double-circuit structures will be either the lattice type or the single-shaft steel pole type.

Double-circuit steel lattice structure is characterized by multiple galvanized steel members laced together to form a steel tower. Figure 3.6-4 also shows a double-circuit single-shaft steel pole structure with davit arms supporting suspension insulators, to which the conductors are attached. No anchor guys are utilized for either type of the structure. The structure heights above grade range from 120 feet to 150 feet depending on terrain, maintenance, and acceptable physical separation of conductors from the underlying roads, transmission lines, etc.

For particular locations such as the last structure outside the switchyard, single-circuit, single-shaft tubular steel structures with post insulators will be utilized. Additionally, H-frame type structures, also illustrated in Figure 3.6-4, with flat conductor configuration will be used for line undercrossings. These structures are typically lower in height than double circuit structures.

3.6.2.2 Conductors

The selection of conductor for connecting the plant switchyard to the Tesla substation will be based on current-carrying requirements and the provisions of the National Electrical Safety Code. The conductor that will meet these requirements is single conductor 954 KCM SSAC per phase. This conductor is expected to carry the full current output of the power plant on either circuit for loss of the companion circuit.

3.6.2.3 Foundations

Foundations for the transmission line structures consist of concrete piers reinforced as necessary to withstand design loads. These are formed by augering a hole of appropriate diameter and depth, placement of a cage of reinforcing steel in the augered hole, and filling the hole with high-strength concrete to the appropriate elevation. Single circuit pole structures may be direct-buried or installed on foundations, depending upon the location.

3.6.3 Transmission System Upgrades

As stated earlier in this section, in order to accommodate the termination of the new ties to the TPP without an extension of the existing fenced area at Tesla substation, it will be necessary to re-locate the terminations of two existing transmission lines. Namely, the Tesla-Ravenswood 230kV line will have to be re-located to Bus C (previously named Bus F); and the Tesla-Newark 230kV line will have to be re-terminated from CB232 to CB242 at Bus E. Refer to Figure 3.6-3.

PG&E's Preliminary System Impact/Facilities Study (see Appendix I) indicates that the addition of the TPP project will cause an increase in the short circuit current level at the Tesla substation such that the existing 230kV circuit breakers would be overdutied. Additionally, the design levels of other systems at Tesla substation, such as the ground grid and bus supports, would also be exceeded. This condition will be mitigated by a new 8-ohm current limiting reactor installed between 230kV Bus D and Bus C at Tesla Substation. The line termination and addition of the new reactor will be done within the existing substation fenced area; hence there will be no significant environmental impacts caused by this work.

In addition to the higher short circuit level at the Tesla substation 230 kV buses, the results from the power flow analysis indicate that overloads may occur on several transmission lines due to the operation of the TPP for Category B and C contingencies. PG&E's System Impact/Facilities Study identified the following mitigation alternatives for the Category B contingencies.

3.6.3.1 Category B Contingencies

3.6.3.1.1 Tesla-Newark # 1 230 kV line Overloaded Component: Contra Costa-Las Positas 230 kV line

Mitigation Option: The Contra Costa-Las Positas 230 kV line has been re-rated by PG&E. The only mitigation available is to implement a Special Protection Scheme (SPS) to reduce project output to a level which would eliminate the overload. There will be no environmental impacts associated with this mitigation measure.

3.6.3.1.2 500/230 kV Transformer Bank at Vaca Dixon Sub Overloaded Component: Delta Switching Yard-Tesla 230 kV line

Mitigation Option 1: Re-conductor approximately 7 miles 230 kV transmission line with 1272 ACSR and replace any inadequate terminating equipment to meet the modeled post projected emergency loading of 1198 Amps.

Mitigation Option 2: Implement SPS to reduce project output to a level that would eliminate the overload. This is the option that the TPP will elect to implement and there will be no environmental impacts associated with this mitigation measure.

3.6.3.1.3 500/230 kV Transformer Bank at Vaca Dixon Sub Overloaded Component: Contra Costa-Delta Switching Yard 230 kV line

Mitigation Option 1: A 4 foot-per-second wind speed re-rate of the Contra Costa-Delta Switching Yard 230 kV line would increase the emergency capacity of the 954 ACSR to 1129 Amps. The additional capacity would be adequate to eliminate the emergency overloads. This would involve approximately 18 circuit miles of line. If a re-rate is appropriate, it would not result in any environmental impacts.

Mitigation Option 2: Implement SPS to reduce project output to a level that would eliminate the overload. There would be no environmental impacts associated with this mitigation measure.

3.6.3.2 Category C Contingencies

Unlike CAISO Category B outages, CAISO Category C outages (according to WSCC reliability criteria) may be mitigated by load shedding or generation dropping. Therefore, the TPP developer is not required to mitigate the CAISO Category C outages by installing new or upgrading the existing transmission facilities. However, the PG&E and/or CAISO may require that the developer be responsible for sharing of the costs of new operating procedures and/or special protection schemes that will eventually be required for mitigation of these rare occurrences.

3.7 PROJECT CONSTRUCTION

Engineering, procurement and construction (EP&C) of the TPP is estimated to take approximately 32 months, Figure 3.7-1. The project construction schedule, construction staff and craft manpower, and average frequency of vehicle traffic are detailed in the sections below.

3.7.1 Power Generation Facility

On-site construction of the project is expected to take place from May 2002 to April 2004, a total of 23 months. The schedule has been estimated on a single shift, 10 hour/day and 55-hour/week, based on a schedule of Monday through Saturday. Additional hours may be necessary to make up schedule deficiencies or to complete critical construction activities. During the startup and testing phase of the project, some activities may continue 24 hours per day, 7 days per week. Estimates of the average and peak construction traffic during the on-site construction period are provided in Table 3.7-1

Table 3.7-1 Average and Peak Construction Traffic(2)

Vehicle Type	Average Daily Round Trips	Peak Daily Round Trips(3)
Construction Worker Vehicles(1)(2)	325	649
Delivery Vehicles (including heavy trucks)	20	21
TOTAL	345	670

1. Assumes that 1/3 of the workforce will carpool (1.5 persons per vehicle).
2. Includes construction for project site and transmission line.
3. "Peak" refers to scheduled peak construction months of May and June 2003. Peak workforce during those months is expected to be approximately 974 persons.

The estimated construction workforce by trade and month is shown in Table 3.7-2. Construction staff by month is shown in Figure 3.7-2. The on-site workforce will consist of laborers, craftsmen, supervisory personnel, support personnel, and construction management personnel. The on-site workforce will average approximately 485 worker and will have a peak of approximately 974 workers between the 12^{th} and 14^{th} month of construction.

Primary construction access will be via the I-580 Patterson Pass Road exit, about two miles east of the site, west to Midway road, approximately one mile to the north of the site. Estimates of the average and peak construction traffic during the on-site construction period are also provided in Figures 3.7-3 and 3.7-4. Truck deliveries will normally be on weekdays between 7:00 AM and 5:00 PM.

3.7.2 Gas Transmission Pipeline

The construction of the 2.8-mile, 24-inch natural gas pipeline will be scheduled to be finished and operational in time to provide test gas to the power generation facility. The construction of the pipeline will take approximately 3 months (Table 3.7-1) with an average workforce of 40 people. The pipeline work force will consist of laborers, welders, equipment operators, supervisory personnel, and construction management personnel. Pipeline construction laydown, parking, and storage will be combined with the directional bore staging area.

The pipe will be carbon steel material manufactured in accordance with the American Petroleum Institute (API) Specification for Line Pipe. A factory applied corrosion protection coating will be applied on the pipe. Joints will be welded and coated.

Construction by Trenching or Jack and Bore Techniques

Trenching – Trenching will consist of digging a three to seven foot wide trench. Trench width will depend on the type of soils encountered and underground obstructions. Trench depth will be sufficient to meet the requirements of the governing agencies. However, the pipeline will be buried to provide a minimum cover of 36 inches. The excavated soil will be piled on one side of the trench and used for backfilling after the pipe is installed in the trench. The pipeline will be installed by trenching at all locations except for road and creek crossings, which may be installed by jacking, slick or dry boring or directional drill.

Stringing – Stringing will consist of trucking lengths of pipe to the right-of-way and laying them on wooden skids beside the open trench.

Installation – Installation will consist of bending, welding, and coating the weld joint areas of the pipe after it has been strung, padding the ditch with sand or fine spoil, and lowering the pipe string into the trench. Bends will be made by a cold bending machine or shop fabricated fittings as required for various changes in bearing and elevation.

Welding will meet API standards and be performed by qualified welders. Welds will be inspected in accordance with API Standard 1104. Welds will undergo 100 percent radiographical inspection by an independent, qualified radiography contractor. All coating will be checked for holidays (i.e., defects) prior to lowering into the trench.

Backfilling – Backfilling will consist of returning spoil back into the trench around and on top of the pipe, ensuring that the surface is returned to its original grade or level. The backfill will be compacted to protect the stability of the pipe and to minimize subsequent subsidence.

Boring – The jack and bore method will be used for the moderately short crossing under roads and creeks. Boring pits will be dug on each side of the crossing. On the inlet side, a boring machine with an auger typically will be used, or a ramming device may be used to "jack" the pipe into place. Normally pipe would be placed between 6 and 10 feet below grade by the jack and bore method and is subject to approval by governing authorities.

Hydrostatic Testing – Hydrostatic testing will consist of filling the pipeline with water, venting all air, increasing the pressure to the specified code requirements, and holding the pressure for a period of time. After hydrostatic testing of the pipeline, the test water will be chemically analyzed for contaminants and discharged into an approved discharge basin. Temporary approvals for test water use and permits for discharge will be obtained as required.

Cleanup – Cleanup will consist of restoring the surface of the right-of-way by removing any construction debris, grading to the original grade and contour, and replanting the disturbed area as agreed upon with the landowner.

Commissioning – Commissioning will consist of drying the inside of the pipeline, purging air from the pipeline, and filling the pipeline with natural gas.

Construction by Directional Drilling

The horizontal directional drilling method will be employed to install the pipeline under the Delta Mendota Canal, the California Aqueduct and I-580, in a single drill.

The bore profile will be engineered by the successful drilling contractor, based upon information gained from soil boring samples and geotechnical evaluation of the drill site. Generally, the pilot hole will enter and exit at an angle of approximately 10 degrees while the deepest point of the bore can achieve a depth of 100 feet or more as the drill head is "steered" through the most favorable geotechnical areas.

The horizontal directional drilling equipment will be set up at an entry point site. It will initially drill a pilot hole. A reaming device will be attached to the drill string and will be pulled through the pilot hole. The reamer will enlarge the pilot hole to a diameter of 35 to 50 percent greater than the final pipeline size. The pipeline string will then be welded, radiographed, and hydrotested, behind the exit point of the drill, after which it will be pulled through the enlarged bore hole and connect to the rest of the pipeline.

Drilling mud will be used as part of the horizontal directional drilled process to lubricate and cool the drill. The mud will be non-toxic bentonite. The excess drilling mud will be collected at the directional drilling site. It will then be disposed of at a Class III landfill.

Easement and Work Space Requirements:

The proposed pipeline follows existing PG&E's Line 107 right-of-way from the PG&E Maintenance Center to Midway Road. A temporary right-of-way will be purchased next to the permanent right-of-way to allow a 100 foot wide work space for equipment during construction. Along the section that parallels Midway Road, FPL expects to purchase a 25 foot permanent right-of-way with an additional 75 feet of temporary work space.

Additional temporary work space will be required at the entry and exit point for the horizontal directional drill. The entry point where the drill rig, mud mixer and water tanks are staged requires a temporary work area of 100 feet by 200 feet. It is expected that this area would be located on the north east side of the Mendota Canal. The exit point on the south east side of I-580 would require an area 75 feet by 100 feet. The equipment in this area would included pumps and mud tanks.

For those areas where the pipe may be placed by the jack and bore method such as Patterson Run and Midway Road, sufficient room should be available for equipment within the permanent and temporary right-of-way.

Additional property will be purchased at the tie-in point with PG&E Line 401, to set above ground equipment such as meters, regulators, and valves. The extent and exact location of this property is subject to negotiations with PG&E.

3.7.3 Transmission Line

Construction of the 0.8 mile transmission line interconnection to PG&E's Tesla Substation will take approximately 4 months. The construction workforce will be located at the project site and is included in Table 3.7-1. The transmission line construction laydown and staging area will be at the on-site construction area.

3.7.4 Water Supply Pipeline and Pump Station

Construction of the 1.7-mile, 20-inch water supply pipeline will take approximately 2 months (Table 3.7-1) with an average workforce of 32 people, respectively. The pipeline work force will consist of electricians, laborers, welders, equipment operators, supervisory personnel, and construction management personnel.

3.7.5 Construction Plan

An EP&C contractor will be selected for the design, procurement, and construction of the facility. The EP&C contractor will select subcontractors for certain specialty work as required.

3.7.5.1 Mobilization

The EP&C contractor will mobilize approximately one month after project certification. Site preparation work will include site grading and storm water control. Gravel will be used for temporary roads, laydown, and work areas.

3.7.5.2 Construction Offices, Parking and Laydown Areas

Mobile trailers or similar suitable facilities (e.g., modular offices) will be used as construction offices for contractor and subcontractor personnel. Construction laydown and parking areas are illustrated in Figure 3.5-3. Site access will be controlled for personnel and vehicles. A security fence will be installed around the plant site boundary, including the laydown area.

3.7.5.3 Emergency Facilities

Emergency services will be coordinated with the local fire department and hospital. An urgent care facility will be contacted to set up non-emergency physician referrals. First-aid kits will be provided around the site and regularly maintained. At least one person trained in first aid will be part of construction staff. In addition, all foremen and supervisors will be required to have first-aid training. Fire extinguishers will be located throughout the site at strategic locations at all times during construction.

3.7.5.4 Construction Utilities and Site Services

During construction, temporary utilities will be provided for the construction offices, laydown area, and the project site. Temporary construction power will be utility-furnished power. Area lighting will be provided and strategically located for safety and security.

Construction water will be provided from the existing on-site well or delivered via truck. Average daily use of construction water is estimated to be about 8,000 gallons. A maximum daily water usage is estimated at 85,000 gallons during hydrotest. The hydrotest water will be tested. If suitable for discharge, it will be routed to the sedimentetation/detention pond. If the water quality is not suitable for discharge, it will be transported by trucks to an approved off-site disposal facility.

The following site services will be provided by the general contractor:

- Environmental Health Safety Training
- Site Security
- Site First Aid
- Construction testing (NDE, Hydro, etc.)
- Site fire protection and extinguisher maintenance
- Furnishing and servicing of sanitary facilities
- Trash collection and disposal
- Disposal of hazardous materials and waste in accordance with local, state, and federal regulations

3.7.5.5 Construction Materials and Equipment

Construction materials such as concrete, pipe, wire and cable, fuels, reinforcing steel, and small tools and consumables will be delivered to the site by truck.

Most of the heavy equipment will be transported by rail to the common shipping depot nearest to the site. Rail deliveries will be off-loaded and transported to the site by common carrier.

3.7.6 Construction Disturbance Area

The power plant site is presently unoccupied agricultural land used for grazing, as shown in Figure 3.3-1. Estimated land disturbances for construction and operation of the project, including the power plant, transmission line, and pipeline, are presented in Table 3.7-3.

3.7.7 Landscaping

The plant site will be landscaped in accordance with the conceptual landscape plan shown in Figure 3.7-5. This plan relies on topographic analysis of the project site and concentrates on those viewpoints which are most likely to be visible to the general public, i.e. Midway Road. All landscape material proposed has been selected based on climatic and soil conditions of the site.

Table 3.7-3 Estimated Temporary and Permanent Land Disturbance Area

Project Component	Acres	Notes
Power Generation Facility • Temporary • Permanent	 40.0 25.0 Total 65.0	Temporary disturbance area includes the construction office, equipment laydown area, and craft parking on the project site and adjacent 49 acre parcel (see Figure 3.5-3). Permanent disturbance area includes the fenced areas of the power generation facility, the switchyard, the 5 ac-ft detention basin area, and plant access road.
Transmission Line • Temporary • Permanent	 0.9 0.1 Total 1.0	Transmission line from the site switchyard to the PG&E Tesla Substation is about 4,000 feet in length, requiring approximately 20 pole structures. Approximately 12 structures will be located on the temporary disturbed area of power generation facility and the remaining 8 will require a construction area of about 5,000 sq ft per structure, a total of 40,000 sq ft. Permanent average disturbance is 100 sq ft per structure.
Ravenswood Relocation • Temporary • Permanent	 0.4 0.1 Total 1.7	Ravenswood transmission line relocation is approximately 1,760 feet long requiring 3 structures. Temporary disturbance will be approximately 5,000 sq ft per structure (total of 15,000 sq ft). Permit disturbances 100 sq ft per structure (300 sq ft).
Natural Gas Pipeline • Temporary • Permanent	 36.2 0 Total 36.2	Pipeline is 2.8 miles in length (14,784 feet). Approximately 5,500 feet of the pipeline will be bored beneath the two canals, I-580, and beneath two crossings of Patterson Run Creek. Temporary construction disturbance for the 9,284 feet of pipeline will be 100-feet wide for a total of 21.2 acres. There will be three directional bore or pipe-jack locations that will each require 2.5 acres at entry site and exit sites (total of 15 acres). Permanent 50-foot pipeline easement, but surface restored to agriculture use or natural habitat. No temporary or permanent access road.
Water Supply Pipeline • Temporary • Permanent	 10.3 0.5 Total 10.8	Water supply pipeline length from California Aqueduct to site property line is 1.7 miles. Construction disturbance will be 50 feet wide, for a total of 10.3 acres. Along the water pipeline route, the surface will be restored to existing condition. No temporary or permanent access road will be required. Permanently disturbed area is for the pumping station (0.5 acres). The pumping station construction will be within the permanently disturbed area of the station.

3.8 FACILITY OPERATION

The power plant will be controlled and operated by three individuals during each operating shift. Additional maintenance and supervisory personnel will be present during the day shift and, as required by specific operations or maintenance activities, during evening and night shifts. The project will employ about 36 full-time permanent personnel (Table 3.8-1) with a maximum of 20 employees during the day shift. The power plant will normally be operated 7 days per week, 24 hours per day. When the plant is not operating, personnel will be present as necessary for maintenance and to prepare the plant for startup. During extended outages when no operations or maintenance activities are in progress, at least one individual will be on-site during all hours for security purposes.

Table 3.8-1 Plant Operation Workforce

Department	Personnel	Shift	Workdays
Production	11 Plant Operators 14 Production Technicians	Rotating 12-hour shift, 6 or 7 employees per shift	7 days a week.
Production Assurance	6 Production Specialists	Standard 8-hour days	5 days a week with additional coverage as required.
Administration	2 Plant Management 3 Plant Technicians	Standard 8-hour days	5 days a week with additional coverage as required.

Overall annual availability of the power plant is expected to be in the range of 92 to 98 percent. The power plant's capacity factor will depend on market prices for electricity, ancillary services, and natural gas. The design of the power plant provides for operating flexibility (i.e., ability to start up, shut down, turn down, and provide peaking output) so that operations may be readily adapted to changing conditions in the energy and ancillary services markets.

Operation of the power plant will reflect the prevailing volatility in the energy marketplace. When electricity prices are higher than the incremental cost of power produced by the plant, output from the plant will tend to be increased. When electricity prices are lower than the decremental cost of power produced by the plant, output from the plant will tend to be decreased or curtailed. If prices are expected to remain below the cost of production for a period of several hours, one CTG may be shut down and later restarted when prices have rebounded sufficiently. If prices are expected to remain at very low levels for a period of several hours, or are expected to remain below the cost of production for an extended period of time, both CTGs and the STG may be shut down and later restarted when prices have rebounded sufficiently.

Power produced by the plant will be sold in wholesale energy markets or to energy market participants on a bilateral basis. To the extent bilateral sales are based on stable pricing or necessitate a specific mode of plant operation, the plant will be less reactive to volatility in the energy marketplace. Depending on market prices and the provisions of bilateral sales, in any given hour the plant may be operating at peak load, base load, part load with one or more

CTG, or the plant may be entirely shut down. Peak load operation will tend to occur during summer on-peak hours, minimum load operation during non-summer off-peak hours, and shut down periods during non-summer weekends. Shut down periods for annual maintenance will be scheduled during extended periods of low prices, which typically occur in the winter or spring.

Ancillary services provided by the plant will be sold to wholesale energy markets and possibly to other market participants. These services include regulation, operating reserves to the extent the plant is not operating at full load, and reactive power production. Black start capability will not be provided.

3.9 FACILITY CLOSURE

Facility closure can be temporary or permanent. Temporary closure consists of a cessation in operations for a period of time greater than the time required for normal maintenance, including overhauls or replacements of major equipment. Potential causes for temporary closure include economic conditions or repairable damage to the plant from earthquake, fire, storm, or other such events. Permanent closure consists of a cessation in operations with no intent to restart operations. Potential causes for permanent closure include age of the plant, economic conditions, or irreparable damage to the plant. Temporary and permanent facility closures are discussed in the following sections.

3.9.1 Temporary Closure

In the event of a temporary closure, 24-hour security for the facility will be maintained and the California Energy Commission (CEC) will be notified. Actions taken will depend on whether the temporary closure involves a release of hazardous materials.

If there is no release or threatened release of hazardous materials, a contingency plan for the temporary cessation of operations will be implemented. The contingency plan will be conducted to assure public health and safety, protection of the environment, and conformance with all applicable laws, ordinances, regulations, and standards. Appropriate procedures will depend on the anticipated duration of the shutdown. Accordingly, the contingency plan may include the draining of chemicals, water, and other fluids from storage tanks and plant equipment and various other procedures to ensure worker safety and to protect plant equipment. All hazardous and non-hazardous waste materials will be collected and disposed of as described in Section 5.12.

If there is a release or threatened release of hazardous materials, procedures set forth in a Risk Management Plan (RMP) will be implemented. The RMP to be prepared is described in Section 5.12. Procedures include methods to control releases of hazardous materials, notification of appropriate authorities and the public, training for plant personnel, and other emergency response actions and preparation. Once the release of hazardous materials has been contained and cleaned up, temporary closure will proceed as in the case of a closure where there is no release of hazardous materials.

3.9.2 Permanent Closure

The planned operational life of the facility is 30 years. However, if the facility continues to be economically viable, it could be operated for a longer period of time. Operation beyond 30 years would defer environmental impacts resulting from the construction of replacement facilities. It is also possible that the facility could become economically non-competitive before 30 years have transpired, forcing early decommissioning. Whether the facility is closed at the expiration of 30 years, after more than 30 years, or prior to 30 years due to economic or other reasons, procedures set forth in a decommissioning plan will be implemented. The decommissioning plan to be prepared is described below.

To assure public health and safety, protection of the environment, and conformance with applicable laws, ordinances, regulations, and standards, the decommissioning plan will be submitted to the CEC for review prior to commencement of permanent facility closure measures. Such measures may range from extensive "mothballing" to removal of all equipment and appurtenances, depending on circumstances at the time. However, future conditions that would affect decommissioning decisions are largely unknown at this time. It is therefore appropriate to present decommissioning details to the CEC and other jurisdictional agencies when more information is available and the time for permanent facility closure has drawn closer.

The decommissioning plan will include the following:

- Description of the proposed decommissioning measures for the facility and for all appurtenances constructed as part of the facility.
- Description of the activities necessary to restore the site if the decommissioning plan calls for removal of all equipment and appurtenances.
- Discussion of decommissioning alternatives other than restoration of the site.
- Presentation of the costs associated with the proposed decommissioning measures and the source of funds to pay for the decommissioning.
- Discussion of conformance with applicable laws, ordinances, regulations, and standards and with local and regional plans.

In general, the proposed decommissioning measures will attempt to maximize the recycling of all facility components. Unused chemicals will be sold back to the suppliers or other purchasers. All equipment will be shut down and drained so as assure public health and safety and protection of the environment. All hazardous and non-hazardous waste materials described in Section 3.4.7 will be collected and disposed of as described in Section 5.12. Until decommissioning activities have been completed, 24-hour security for the facility will be maintained.

3.10 ALTERNATIVES

The following sections discuss alternatives to the TPP as proposed in this AFC. These include the "no project" alternative, power plant site alternatives, transmission interconnection alternatives, natural gas pipeline route alternatives, technology alternatives, water supply alternatives, and wastewater disposal alternatives. These alternatives are discussed in relation to the environmental, public policy, and business issues embodied in the objective of the proposed project. The objective of the TPP is to utilize the available resources for the production of economical, reliable, and environmentally sound electrical energy, capacity, and ancillary services for California's restructured energy market.

3.10.1 "No Project" Alternative

As discussed in Section 2.2, the CEC has determined that California will need a substantial amount of additional generation capacity over the next several years, and the proposed project will serve to fill part of the identified need. The TPP will provide competitively priced power to the California electricity market to help meet the state's growing demand for electricity and to help replace nuclear and fossil fuel generation resources retired due to age or cost of producing power. The "no project" alternative would not meet these objectives.

In addition, the "no project" alternative would result in more energy production from existing power plants than would otherwise occur with the TPP competing for the opportunity to generate power. Because the TPP will employ advanced combustion turbine technology and state-of-the-art emissions control systems, existing power plants operating in place of the TPP would likely consume more fuel and emit more air pollutants per kilowatt-hour generated.

As a merchant power plant, the business risk associated with the construction and operation of the TPP will be borne entirely by the Applicant. No ratepayer or public monies will be placed at risk. The "no project" alternative would not serve to insulate ratepayers or taxpayers from risk, but instead could harm ratepayers by decreasing competition and thereby increasing electricity prices.

In summary, the "no project" alternative would not serve the growing needs of California's residents and businesses for economical, reliable, and environmentally sound power resources.

3.10.2 Power Plant Site Alternatives

The TPP site was selected for a number of reasons including the following:

- Adequate size and shape to contain the proposed facilities and other site improvements
- Availability (willing seller offering site control)
- Compatibility with local land use plans and zoning ordinances
- Compatible surrounding land uses
- Ease of interconnection for electrical transmission and natural gas supply
- Potential for less than significant environmental impacts (e.g., biological, cultural/paleontological, visual, noise, flooding, and seismic)
- Location of the site in an area with access to multiple markets.

FPL has several projects operating in California and has been actively developing new power generation sites planned for location near load or electrical distribution centers. When FPL began searching for what became the TPP site, an important factor was to have a site that would serve the Greater Bay Area load center and to have access to other markets as well. Another goal was to minimize the length of linear facilities for gas, electricity, and water interconnection in order to minimize cost and environmental impacts. The region surrounding the PG&E Tesla Substation was identified by FPL as having the desired nearby transmission access and natural gas supply, compatible land use, availability of land suitable for development, and the potential to avoid significant impacts to established communities and environmental resources.

Several sites were identified by FPL within a few miles of the Tesla Substation, which became the center of the study region for site selection. Coincidentally, the CEC Staff, during an alternatives analysis for the Metcalf project, evaluated two sites (called Alt-5 and Alt-6) that were located immediately south of the proposed TPP site. These sites were included in the Metcalf evaluation because of the scarcity of sites near that project and because these sites were close to an existing substation (Tesla) and were near natural gas pipelines. In its evaluation, CEC Staff found that, when compared to the Metcalf project, these two alternatives would reduce the potential for impacts to visual and land use, but may need mitigation for potential impacts to biological and water resources.

3.10.2.1 Alternative Site Selection Criteria

During the site selection process, eight other sites were considered by FPL within the Tesla Substation study area. The alternative sites are labeled A through G on Figure 3.10-1. Each of these sites met the basic criteria for sufficient size (approximately 50 acres), compatibility with local land use plans and zoning ordinances. Consideration of these potential sites by FPL included discussions with each landowner regarding the potential for acquiring the sites. A willing seller was identified so that site control could be obtained if the site was selected. For final selection, the criteria used to evaluate the suitability of the alternative sites for TPP were as follows:

- Interconnection requirements for electrical transmission and natural gas supply
- Access to site and need for new roads
- Potential for less than significant environmental impacts (e.g., biological, cultural/paleontological, visual, noise, and other resources)

The characteristics of each alternative site are presented in Table 3.10-1.

3.10.2.2 Evaluation of Site Alternatives

In this section, the potential environmental impacts of the alternative sites are discussed relative to the proposed site.

Air Quality. The type and quantity of air emissions from the proposed site and alternative sites will be identical. However, the impacts on the human population and the environment could differ because of the location of residences and other human habitat in the vicinity of the sites and the terrain surrounding the alternative sites. Sites E, F, and G each have nearby elevated terrain that would require taller exhaust stacks to reduce impacts to levels that are not significant.

Biological Resources. Types of biological resources in the area of the alternative sites are generally comparable to those identified at the proposed project site. All of the alternative sites are located in grazed fields similar to the project site. Burrowing owls are common in the area and would be expected at each of the alternative sites. All of the sites are within the range of the San Joaquin kit fox, ferruginous hawk, Swainson's hawk, mountain plover, white-tailed kite, California horned lark, San Joaquin whipsnake, California horned lizard, California tiger salamander, and western spadefoot toad. Biological resources addressed below are vegetation and special-status plant species, wetlands, and wildlife and special-status animal species.

Vegetation and Special-Status Plant Species.

Proposed Site. The proposed site consists of nonnative grassland dominated by *Bromus diandrus.* The site is heavily disturbed by grazing and other activities associated with cattle grazing. Surveys conducted in May 2001 revealed no special-status plant species, and the area is too highly disturbed to expect it to support populations of special-status plants.

Alternative A. Alternative A is located directly north of the proposed site on the west side of Midway Road. The area is grazed and dominated by nonnative annual grasses. Surveys conducted in May 2001 revealed no special-status plant species, and the area is too heavily disturbed by grazing to expect it to support populations of special-status plants.

Alternative B. Alternative B is located southeast of the proposed site. It consists of nonnative annual grassland. Patterson Run Creek crosses the southeast corner of this Alternative, and contains willow trees along its banks. Patterson Run Creek is a designated habitat for the red-legged frog, a California endangered species. This alternative site is grazed and periodically disturbed to create firebreaks along the road and around the electrical transmission towers. Surveys of the Alternative B site in May 2001 revealed no special-status plant species, and the area is too highly disturbed by grazing to be expected to support populations of special-status plants. Proximity of this site to Patterson Run Creek has the potential for greater impacts to riparian habitats, in comparison with the proposed project site.

Alternative C. Alternative C is located south and southwest of the proposed site. The land is nonnative annual grassland. Similar to the proposed site and Alternatives A and B, the site is grazed and periodically disturbed to create firebreaks around electrical transmission towers and windmills. The area is too highly disturbed by grazing to be expected to support populations of special-status plants.

Alternative D. Alternative D is located directly south of Alternative C. The vegetation and disturbance regime is the same as that of the proposed site and Alternatives A, B, and C, and thus is not expected to support populations of special-status plants. Portions of this site are adjacent to Patterson Run Creek. Development of this site could lead to greater impacts to riparian habitats associated with the creek.

Alternative E. Alternative E is located south of the Tesla Substation. The area is classified as nonnative annual grassland and is dominated by *Bromus diandrus*. Records indicate that the area south of the Tesla Substation including this alternative site supports populations of big tarplant, although none were observed during surveys conducted in June 2001, which coincides with the blooming period for big tarplant. The area is heavily disturbed by grazing, and may no longer support populations of special-status plant species.

Alternative F. Alternative F is located directly south of Alternative E. This site was also surveyed in June 2001, and the vegetation characteristics, disturbance regime, and survey results are similar to Alternative E.

Alternative G. Alternative G was not surveyed however the site is expected to have nonnative annual grasslands impacted by grazing, similar to the other alternatives.

Wetlands.

Proposed Site. The proposed site contains no wetlands. USGS 7.5' (1:24,000-scale) topographic maps dated 1953 (photo revised 1980) reveal an intermittent stream in the southern portion of the site. Cultivation and grazing activities have modified this feature and it no longer supports wetland plant species or has the hydraulic or soils characteristics of a wetlands.

Alternative A. Alternative A contains no wetlands.

Alternative B. Patterson Run Creek crosses the southeast corner of Alternative B. The creek contains riparian/wetland vegetation such as willows and rushes. However, this portion of Patterson Run Creek is only periodically wet and does not support stands of wetland vegetation. There is evidence of flashy flows, rather than ponding water along the portion of Patterson Run Creek that is within Alternative B.

Alternatives C, E, F. Alternatives C, E, and F contain no wetlands.

Alternative D. Patterson Run Creek is adjacent to Alternative D and development at this site has more potential for impacts to riparian habitat from the proposed site.

Alternative G. An intermittent stream crosses the site and is expected to have seasonal riparian habitat.

Wildlife and Special-Status Species.

Proposed Site. As described in Section 5.3, the proposed site is used extensively for grazing, and there are patches of bare soil throughout the project site caused by cattle movement. There is also a stock tank on the proposed project site, which contains water but no associated wetland vegetation. There are numerous small mammal burrows, ground squirrels, and cottontail rabbits on the site. Transmission lines cross the site, which provide perching sites for foraging raptors. Burrowing owls have been observed on the project site.

Alternative A. Alternative A provides potential habitat for the same species as those at the proposed site. During field surveys in May and June 2001, burrowing owls were identified on the site.

Alternative B. Alternative B provides potential habitat for the same species as the proposed site. Additionally, Patterson Run Creek crosses the southern portion of this alternative and may serve as a migration corridor for the California red-legged frog. Patterson Run Creek is a designated critical habitat for the red-legged frog. Surveys of the area in May and June 2001 revealed no special-status wildlife species.

Alternative C. Alternative C provides potential habitat for the same species as the proposed site. This site has not been surveyed, however the habitat appears similar to the project site and burrowing owls in the area, and the classification of the area as San Joaquin kit fox habitat necessitate a recommendation that surveys for special-status wildlife species be conducted before any further action at the site.

Alternatives D. This alternative site is adjacent to Patterson Run Creek which is designated as critical habitat for the red-legged frog. A potential kit fox den has been identified approximately 500 feet east of Alternative D.

Alternatives E and F. Alternatives E and F provide potential habitat for the same species as the proposed site. Surveys conducted in June 2001 revealed burrowing owls on both of these sites.

Alternatives G. This alternative site has not been surveyed, however habitats similar to the project site indicate the potential for burrowing owl and San Joaquin kit fox. An intermittent drainage through the center of the site may offer opportunities for species preferring riparian areas.

Cultural Resources. An archival records search was conducted that included the proposed project site and the alternative sites. No records of prehistoric sites were noted during the review of archival information. Two historic sites were found, both near the PG&E Tesla Substation, but not within or adjacent to any of the alternative sites.

Based on the archival research and limited site surveys, the alternative sites are all expected to have cultural resources that are the same as the proposed site.

Land Use. The project site and Alternatives A through F are located in Alameda County. All of these sites are zoned large-parcel agricultural. Based on discussions with the Alameda

County Planning Staff, the large-parcel agricultural zoning designation is consistent with the siting of an electrical generating facility and no zoning change is required. Therefore, the land uses impacts for the proposed site and Alternatives A through F are similar.

Surrounding land uses for the alternatives are generally similar to the project site with grazing and wind farms predominating in the area. Alternatives E and F have rural residences nearby. Alternative G is bordered on the east side by an agricultural products processing complex, but has grazing lands on the other sides of the site.

Noise. Alternative A is more distant from potential sensitive receptors (rural residences) than the proposed site. All the other alternative sites are closer to potential receptors. Alternatives D, E, and F are closest to receptors (less than 2,000 feet) and could require additional mitigation to reduce potential impacts to levels that are less than significant.

Public Health. Impacts to public health arise mainly from air emissions. The type and quantity of air emissions from the proposed and alternative sites will be identical. However, the impacts on the human population and the environment could differ because of the location of residences and other human habitat in the vicinity of the sites and the terrain surrounding the alternative sites. Sites E, F, and G each have nearby elevated terrain that would require taller exhaust stacks to reduce impacts to levels that are not significant.

Worker Health and Safety. Construction of TPP at the proposed site has no impact on worker health and safety and none of the alternative sites have characteristics that would impact worker health and safety.

Socioeconomics. Property taxes from TPP at the proposed site, as well as Alternatives A through F, will benefit Alameda County. Alternative G is located in San Joaquin County, so property taxes would benefit that county. Because the alternatives are all within approximately two miles of the proposed site, all socioeconomic impacts are expected to be similar to the proposed site. Other socioeconomic impacts from the alternatives are believed to be the same as impacts from the proposed site.

Agriculture and Soils. The major differences between the proposed TPP site and the alternative sites were compared for their effects on prime agricultural land and potential for erosion during construction. A comparison of soils and farmland types is presented in Table 3.10-2.

Traffic and Transportation. The proposed site and the alternatives will each require a new access road connection to either Midway Road or Patterson Pass Road. The longest access road is Alternative F, which would require a 0.7 mile access road from Patterson Pass Road to the west. Because alternatives are all within two miles of the proposed site with access to be provided from either Midway Road or Patterson Pass Road, traffic patterns for both construction and operation are expected to be similar. Traffic and transportation impacts would be similar for the proposed project and the alternative sites.

Visual Resources. All of the alternative sites consist of parcels that are relatively undisturbed grazing or agricultural land located in rural areas. Views in the areas surrounding Alternatives A through F are influenced mainly by their proximity to the PG&E Tesla Substation, the pressures of large transmission lines, and the presence of windmills and other components of the windfarms on surrounding hills. The potential for visual resources impacts associated with each of these sites varies depending on the relative visibility of the sites from roads and residences and the length and potential visibility of any new transmission lines that development of a generating facility on the site would require.

The project site is most visible by viewers on Midway Road, with more distant views from Patterson Pass Road, passengers on the Western Pacific Railway, and the rural residences approximately 1.0 mile from the site. Alternative A would be more distant from Midway Road, and because of intervening terrain, would be less visible to viewers from Midway Road. Alternatives B and C would have views similar to those of the proposed site from Midway Road and other viewpoints. Alternative D is adjacent to Patterson Pass Road and the Western Pacific Railway, and is closer to rural residences, so visual impacts to those viewers are expected to be higher than for the proposed site.

Alternatives E, F, and G are adjacent to the Western Pacific Railway and closer to residences than the proposed site. Because of the proximity to residences and viewers from passenger trains, visual impacts are expected to be greater than for the proposed site.

Hazardous Materials Handling. The same quantity of hazardous materials would be stored and used at the proposed site as at the alternative sites. Delivery routes for Alternatives A through G would be the same as the proposed site.

Waste Management. The same quantity of waste will be generated at the proposed site as at the alternative sites. The environmental impact of waste disposal should not differ significantly between the proposed and alternative sites. Waste transportation routes for Alternatives A through G would utilize Midway Road and Patterson Pass Road similar to the proposed site.

Water Resources. The quantity of water required will be the same for the proposed site and the alternatives. Alternatives A through F could utilize the same water turnout point on the California Aqueduct. Alternatives A through F would require somewhat longer pipelines than the proposed site, ranging from 1.9 to 2.6 miles in length as compared to 1.7 miles for the proposed site. For Alternative G, a turnout on the California Aqueduct located near the Patterson Pass overcrossing would result in a pipeline length of about 1.1 mile. Water supply pipelines for all of the alternatives are generally within the right-of-way of Midway Road or Patterson Pass Road with short sections from those roads to each site.

Geologic Hazards and Resources. Site-specific geotechnical investigations and implementation of mitigation measures will reduce or eliminate the potential for significant impacts from site-specific geologic conditions.

3.10.3 Transmission Interconnection Alternatives

As an alternative to the interconnection configuration described in Section 3.6, consideration was given to looping one or more of the PG&E 230 kV lines, which run north out of Tesla Substation into the TPP. These lines include the double circuit lines to Tracy and Stagg. However, due to the limited ampacity of these lines, in order to accommodate the maximum output of the TPP in this fashion it would be necessary to either loop 2 of the lines into TPP and reconductor/rebuild the lines, or loop in 4 of the lines into a relatively large new switchyard at the plant. Both of these approaches are more costly and could have a greater impact on the environment than the interconnection configuration presented in Section 3.6.

3.10.4 Natural Gas Supply Pipeline Route Alternatives

The TPP will require approximately 200 million standard cubic feet per day (scf/d) of natural gas for operations. Delivery of gas in this volume requires interconnection to a major gas transmission line or to a local distribution network with sufficient transmission capacity.

The TPP is located approximately 2.8 miles from a PG&E natural gas main that has the capacity to meet project needs. Four alternative natural gas pipeline routes were considered as illustrated in Figure 3.10-2. All of the alternatives have the same connection point with the PG&E main line and will need to cross the Delta Mendota Canal, the California Aqueduct, and the I-580 freeway. The alternative routes range from 2.4 to 4.2 miles in length. Characteristics of each route are summarized in Table 3.10-4.

Table 3.10-4 Natural Gas Pipeline Route Alternatives

	Alternative			
Characteristic	**A**	**B**	**C**	**D**
Length (miles)	2.8	2.4	2.5	4.2
Directional bore (feet)	3,700	3,700	4,000	2,300 (2)
Land use	Agriculture/ grazing	Agriculture/ grazing; wind farm	Agriculture/ grazing; wind farm	Commercial; highway infrastructure

Alternative A. This alternative follows the route of the existing PG&E pipeline #107 from the PG&E mainline connection to its intersection with Midway Road, approximately 3000 feet south of the project site. The pipeline then follows Midway Road to the project site. This route was selected as the preferred alternative because it follows an existing pipeline route and is expected to have the least impacts to land uses along the route. This route has two crossings of Patterson Run Creek which will requires directional bores to avoid impacts to that creek.

Alternative B. Similar to Alternative A, this route follows the PG&E pipeline #107 for about half of its length, however it takes a more direct route to the site after crossing the two canals and the I-580 freeway. In comparison with Alternative A, this route avoids crossing Patterson Run Creek, thus reducing potential impacts to biological resources. This route may have land use conflicts with wind farms that are located along the route.

Alternative C. This route does not follow the PG&E pipeline #107 route; a new pipeline corridor would be required. This route has approximately the same length of directional bore (3,700 feet) as Alternatives A and B. This route may have land use conflicts with wind farms along the route.

Alternative D. Alternative D is the longest of the alternatives at 4.2 miles. From the origin at the PG&E mainline, this pipeline follows Mountain House Road, Patterson Pass Road, and Midway Road to the site. This alternative avoids agricultural and grazing land, however is has potential land use conflicts with commercial land uses along the route. Because of the crossing points for the two canals and I-580 freeway, this alternative is likely to require two separate directional bores.

3.10.5 Water Supply Alternatives

The following cooling water alternatives were considered for the project.

Secondary wastewater from the City of Tracy Sewage Treatment Plant: the City of Tracy operates a secondary treatment plant that produces an average of 6.7 mgd. Currently the entire 6.7 mgd of treated wastewater is discharged into the Old River just north of the City of Tracy. To tap this source, MPL would have to construct wastewater supply and return lines to and from the TPP over a distance of approximately 7 miles. Based upon discussions with City of Tracy staff, it was determined that the City of Tracy would be unable to meet the requirements of the TPP. Furthermore, treatment to reduce total dissolve solids (TDS) to the current waste discharge requirements was determined to be economically infeasible.

Secondary wastewater from the City of Modesto: the City of Modesto has a secondary treatment plant that treats an average daily flow of 25 mgd. The treated water is held and discharged both on land and into the Tuolumne River. As with the City of Tracy, the location of the City of Modesto facilities makes them geographically undesirable. To tap this source, MPL would have to construct wastewater supply and return lines to and from the TPP over a distance of approximately 24 miles. Based upon discussions with City of Modesto staff, it was determined that the City of Modesto would be unable to meet the requirements of the TPP. Furthermore, treatment to reduce total dissolve solids (TDS) to the current waste discharge requirements was determined to be economically infeasible.

Irrigation water from the Modesto Irrigation District was evaluated: water from the MID irrigation canals was to be pumped from its westernmost point to the project via a new water pipeline. The relatively low TDS of this water would have allowed the project to cycle the cooling tower water up to 10 times and still have generated a water of comparable quality to the Central Valley Project water that could be reused for irrigation in the Tracy area. Lower TDS in the circulating water would have reduced particulate emissions from the tower as well. The projected project annual average water demands of 5,100 acre-feet per year for this option was a very small part of the available supply. The value of water reuse with this option was significant even though the requirement for a new 20 mile water pipeline also presented a significant challenge. Due to seasonal shutdowns of the MID system it was determined that water would be unavailable up to 4 months of the year with this alternative. As a result this alternative was dropped due to being infeasible from a reliability perspective.

Secondary wastewater from the nearby community of Mountainhouse: Mountainhouse will construct and operate its own water treatment facility. Phase I is scheduled for completion during the summer of 2002. Phase I will produce 0.225 mgd treated to a tertiary level with a TDS of approximately 300 mg/L. Phase II is scheduled to be online in 2007. Phase II will bring production to 0.45 mgd. Phase III will be completed within the buildout period for Mountainhouse of 25 years. Total Plant production will be 5.4 mgd. Treated effluent will be discharged into the Old River. Based upon this construction schedule and productivity, Mountainhouse's treatment facility will not produce sufficient water to meet the TPP's annual average requirement of approximately 5,100 AF/year and supplies from both phase I and II were already committed to other purchasers.

Irrigation Return Flow: several local irrigation districts were contacted regarding their ability to supply irrigation return flow to the TPP site as a source of cooling water. Based upon discussions with the districts it was determined that they would be unable to meet the TPP's requirements due to the practice of not irrigating during winter months, distance from the TPP site, and unavailability of their supply. All of the remaining options were rejected as being environmentally unacceptable, economically unsound, or both:

- Wastewater from nearby industrial facilities;
- Importing ocean or brackish water;
- Wet-dry cooling; and
- Dry cooling.

3.10.6 Alternative Technologies

The configuration of the TPP was selected from a wide array of technology alternatives. These include generation technology alternatives, fuel technology alternatives, combustion turbine alternatives, NO_x control alternatives, inlet air cooling alternatives, and cooling technology alternatives as discussed below.

3.10.6.1 Alternative Power Generation Technologies

Selection of the power generation technology focused on those technologies that can utilize natural gas. The following provides a discussion of the suitability of such technologies for application to the TPP:

3.10.6.1.1 Conventional Boiler and Steam Turbine

This technology burns fuel in the furnace of a conventional boiler to create steam. The steam is used to drive a steam turbine-generator, and the steam is then condensed and returned to the boiler. This is an outdated technology that is able to achieve thermal efficiencies up to approximately 36 percent when utilizing natural gas, although efficiencies are somewhat higher when utilizing oil or coal. Due to this low efficiency, the conventional boiler and steam turbine technology was eliminated from consideration.

3.10.6.1.2 Simple Cycle Combustion Turbine

This technology uses a combustion turbine to drive a generator. Combustion turbines have relatively low capital cost, and aeroderivative units are able to achieve thermal efficiencies up to approximately 38 percent. Because of its quick startup capability and relatively low capital cost, this technology is used primarily in peaking applications (less than 1,000 hours per year), where relatively low efficiency is not an overriding concern. Because of its relatively low efficiency, this technology tends to emit more air pollutants per kilowatt-hour generated than more efficient technologies. Due to less than optimal environmental performance and relatively low efficiency, the simple cycle combustion turbine technology was eliminated from consideration.

3.10.6.1.3 Conventional Combined Cycle

This technology integrates combustion turbines and steam turbines to achieve higher efficiencies. The combustion turbine's hot exhaust is passed through an HRSG to create steam used to drive a steam turbine-generator. This technology is able to achieve thermal efficiencies up to approximately 52 percent, considerably higher than most other alternatives. This high efficiency also results in relatively low air emissions per kilowatt-hour generated. For these reasons, the conventional combined cycle is considered the benchmark against which all other base load and intermediate load technologies are compared. Because of its high efficiency and superior environmental performance, this technology was selected for the TPP as well as for most other new base load and intermediate load power plants being developed in the United States.

3.10.6.1.4 Advanced Combustion Turbine Cycles

There are a number of efforts to enhance the thermal efficiency of combustion turbines by injecting steam, intercooling, and staged firing. These include the steam injected gas turbine (STIG), the intercooled steam recuperated gas turbine (ISRGT), the chemically recuperated gas turbine (CRGT), and the humid air turbine (HAT) cycle. The STIG is less efficient than conventional combined cycle technology and is only able to achieve thermal efficiencies up to approximately 40 percent. None of the remaining technologies, ISRGT, CRGT or HAT, is commercially available. Consequently, all of these technologies were eliminated from consideration.

3.10.6.2 Alternative Fuel Technologies

Technologies based on fuels other than natural gas were eliminated from consideration because they do not meet the project objective of achieving the environmental and operational advantages. Additional factors rendering alternative fuel technologies unsuitable for the proposed project are as follows:

- No geothermal or hydroelectric resources exist in area.
- Biomass fuels such as wood waste are not locally available in sufficient quantities to make them a practical alternative fuel.

- Solar and wind technologies are generally not dispatchable and are therefore not capable of producing ancillary services other than reactive power.
- Coal and oil technologies emit more air pollutants than technologies utilizing natural gas.

The availability of natural gas, as well as the environmental and operational advantages of natural gas technologies, make natural gas the logical choice for the proposed project.

3.10.6.3 Alternative Combustion Turbine Technologies

The latest generation of commercially demonstrated combustion turbine technology, commonly referred to as "F" technology, was selected for the TPP. The selection of this class of combustion turbines was based on economies of scale, thermal efficiency, operational flexibility, and proven status of commercial operation.

Currently available, large combustion turbine models can be grouped into three classes: conventional, advanced, and next generation. Conventional combustion turbines operate at firing temperatures in the range of 2000°F to 2100°F and are available in sizes up to about 110 MW. Advanced combustion turbines operate at firing temperatures above 2300°F and are available in sizes up to about 160 MW. Next generation combustion turbines have higher firing temperatures than the advanced turbines and have additional features that provide greater output and higher efficiencies. Next generation turbines represent models that have been announced by the manufacturers as commercially available, with advertised outputs in the range of 230 to 240 MW.

Examples of commercially available combustion turbines in each class are as follows:

Manufacturer	Conventional	Advanced	Next Generation
Alstom	GT 11N2	GT 24	None
GE	7EA	7FA	7H
Siemens/Westinghouse	501D5A	501F	501G

Advanced combustion turbines offer significant advantages for the proposed project. Their higher firing temperatures offer higher efficiencies than conventional combustion turbines. They offer proven technology with numerous installations and extensive run time in commercial operation. Emission levels are also proven, and guaranteed emission levels have been reduced based on operational experience and design optimization by the manufacturers. In comparison, environmental performance and thermal efficiencies of next generation turbines have not been demonstrated in commercial operation.

The specific advanced combustion turbine model selected for consideration for the TPP is the GE 7FA. This turbine was selected on the basis of its commercially proven status, demonstrated emission levels, high thermal efficiencies, and adequate operational flexibility.

3.10.6.4 Alternative NO_x Control Technologies

To minimize NO_x emissions from the TPP, the CTGs will be equipped with dry low NO_x combustors and the HRSGs will be equipped with post-combustion selective catalytic reduction (SCR) using aqueous ammonia as the reducing agent.

The following combustion turbine NO_x control alternatives were considered:

- Steam injection (capable of 25 to 42 ppm NO_x).
- Water injection (capable of 25 to 42 ppm NO_x).
- Dry low NO_x combustors (capable of 9 to 25 ppm NO_x).

Dry low NO_x combustors were selected because they provide for lower NO_x emissions and lower HRSG makeup water requirements.

Two post-combustion NO_x control alternatives were considered:

- SCR.
- $SCONO_x$™.

SCR is a proven technology and is used frequently in combined cycle applications. Ammonia is injected into the exhaust gas upstream of a catalyst. The ammonia reacts with NO_x in the presence of the catalyst to form nitrogen and water.

$SCONO_x$™ is a new technology and has been installed on a 25 MW combined cycle plant since December 1996. $SCONO_x$™ consists of an oxidation catalyst, which oxidizes CO to CO_2 and NO to NO_2. The NO_2 is adsorbed onto the catalyst, and the catalyst is periodically regenerated. Although a potentially promising technology, $SCONO_x$™ has not been commercially demonstrated on a large power plant. There are several technological and commercial issues remaining to be resolved prior to application of this new technology to the class of large combustion turbines selected for the proposed project.

The following reducing agent alternatives were considered for use with the SCR system:

- Anhydrous ammonia.
- Aqueous ammonia.
- Urea.

Anhydrous ammonia is suitable for use but its handling and storage is more of a concern than the usage of aqueous ammonia. The aqueous ammonia (19 percent ammonia, 81 percent water solution) has been used in many combined cycle facilities and is proposed for the TPP. Urea has not been commercially demonstrated for use with SCR and was, therefore, eliminated from consideration.

3.10.6.5 Alternative Inlet Air Cooling Technologies

Combustion turbine output and efficiency both increase as inlet air temperature decreases. Ambient air temperatures for the proposed project are sufficiently high for a large portion of the year to warrant some form of inlet air cooling. Three available forms of combustion turbine inlet air cooling are evaporative cooling, inlet fogging, and air chilling.

Both evaporative cooling and inlet fogging are capable of cooling to temperatures near the ambient wet-bulb temperature. Air chilling is capable of cooling inlet air to temperatures below the ambient wet-bulb temperature over a wide range of ambient conditions. Air chilling uses mechanical or absorption refrigeration to produce a cold fluid for cooling of the inlet air, and its capital cost greatly exceeds the cost of evaporative cooling. Air chilling systems may be designed to operate continuously or they may be designed to produce ice or cold water during off peak periods.

Based on temperature profiles at the proposed site, inlet fogging was selected for the TPP to optimize output and efficiency versus capital cost. Inlet fogging offers similar performance to evaporative cooling with lower costs and lower water usage. If warranted by market conditions, the more expensive air chilling alternative may be retrofitted in the future.

3.10.6.6 Alternative Cooling Technologies

There are currently three cooling technology alternatives that are technically feasible for rejecting heat from the combined cycle power plant: wet cooling, dry cooling and a combination of wet and dry cooling technologies – wet/dry (hybrid) cooling technology. Wet cooling requires a conventional evaporative cooling tower and steam surface condenser. Dry cooling requires an air-cooled condenser and wet/dry cooling requires a conventional evaporative cooling tower with surface condenser and an air-cooled condenser. Figures 3.10-3 and 3.10-4 show the equipment layout for the dry and wet/dry cooling technologies. These site plans can be compared with the wet cooling site plan in Figure 3.3-1.

The technical merits of each were considered and wet cooling was selected based on the following criteria/advantages:

- Steam turbine output is lower with dry and wet / dry cooling which results in lower plant efficiency.
- Installed cost for dry and wet / dry cooling is higher.
- Electrical load for dry and wet / dry cooling system is higher, therefore, reducing the plant's net electrical output.
- Dry cooling would occupy about 2 to 3 additional acres. Wet / dry cooling would occupy 1 to 2 additional acres.

Table 3.10-5 provides a quantitative comparison of the alternative cooling technologies.

3.10.7 Alternative Wastewater Disposal Methods

The relatively high TDS of the supply water virtually eliminates direct reuse or an NPDES discharge in the Central Valley due to concerns over TDS loading in the Delta. As discussed in Section 3.10.5 at least one option for lower TDS water was pursued to allow for reuse, but reliability issues for this water removed it from consideration. All other feasible supplies considered had TDS levels similar to or higher than that of the California Aqueduct supply being proposed in the application.

ZLD of some type was clearly indicated with any of these waters. The geology of the area makes deep well injection a very unlikely alternative. The complete dryness scenario being proposed minimizes the total project water use and eliminates seasonal issues that can occur if any significant air drying, such as with evaporation ponds, is relied upon in this climate. Discussions with a nearby manufacturing facility indicated that winter net evaporation is very unreliable, and rainfall in wet years could result in the need for significant oversizing of evaporation ponds.

3.11 APPLICABLE LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

3.11.1 Engineering Geology

Unless specifically stated otherwise, the design of all structures and facilities will be based on the laws, ordinances, codes, specifications, industry standards and regulations, and other reference documents in effect at the time of design. Applicable codes and industry standards with respect to the project's engineering geology are summarized in sections of Appendix A, "Foundations and Civil Engineering Design Criteria", and Appendix B, "Structural and Seismic Engineering Design Criteria".

3.11.2 Civil and Structural Engineering

Unless specifically stated otherwise, the design of all structures and facilities will be based on the laws, ordinances, codes, specifications, industry standards and regulations, and other reference documents in effect at the time of design. Applicable codes and industry standards with respect to the project's engineering design criteria, construction and operation are summarized in Appendix A, "Foundations and Civil Engineering Design Criteria", and Appendix B, "Structural and Seismic Engineering Design Criteria".

3.11.3 Mechanical Engineering

Unless specifically stated otherwise, the design of all structures and facilities will be based on the laws, ordinances, codes, specifications, industry standards and regulations, and other reference documents in effect at the time of design. Applicable codes and industry standards with respect to the project's mechanical engineering design criteria, construction, and operation are summarized in Appendix C, "Mechanical Engineering Design Criteria". Applicable sections of Appendix D, "Control Systems Engineering Design Criteria", will also be considered.

3.11.4 Electrical and Control Systems Engineering

Unless specifically stated otherwise, the design of all structures and facilities will be based on the laws, ordinances, codes, specifications, industry standards and regulations, and other reference documents in effect at the time of design. Applicable codes and industry standards with respect to the project's electrical engineering design criteria, construction and operation are summarized in Appendix E, "Electrical Engineering Design Criteria". Applicable sections of Appendix D, "Control Systems Engineering Design Criteria", will also be considered.

3.12 REFERENCES

California Building Code (CBC). 1998. Title 24 (Part 2) of the California Code of Regulations.